BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
HAWAIIAN ELECTRIC COMPANY, INC.	)	Docket No. 2008-0083
	)	
For Approval of Rate Increases and Revised Rate Schedule and Rules	)	

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HECO
2009 TEST YEAR

HECO SUPPLEMENTAL TESTIMONIES AND EXHIBITS

Book 3 of 3

July 20, 2009

HECO ST-15C
DOCKET NO. 2008-0083

SUPPLEMENTAL TESTIMONY OF
LEON R. ROOSE

MANAGER
SYSTEM INTEGRATION DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Employee Count

INTRODUCTION

Q. Please state your name and business address.

A. My name is Leon R. Roose and my business address is 820 Ward Avenue, 4th Floor, Honolulu, Hawaii 96813.

Q. By whom are you employed and in what capacity?

A. I am the Manager of the System Integration Department for Hawaiian Electric Company, Inc. ("Hawaiian Electric" or "Company"). My experience and educational background are listed in HECO-S-15C00.

Q. What is the purpose of your testimony?

A. My supplemental testimony covers the newly-created System Integration Department and will show that the number of positions created since the 2007 rate case test year settlement that are now located in this department is reasonable.

The New System Integration Department

Q. What is the System Integration Department?

A. As mentioned in HECO ST-7 and HECO ST-15, it is a department created under the new Clean Energy Organization. It is part of the Company's effort to organizationally realign and add resources to manage the workload in order to meet corporate goals to integrate more power generated from clean and renewable resources, including goals established through Hawaii's Renewable Portfolio Standards and the Hawaii Clean Energy Initiative process.

Q. What is the present composition of the System Integration Department?

A. The functional divisions of the System Integration Department include the following:

- Administration (3 positions);
- Generation Planning (9 positions);

- Transmission Planning (8 positions);
- Renewable Energy Planning (4 positions);
- Distribution Planning (7 positions);
- System Protection (4 positions); and
- Advanced Metering Infrastructure (6 positions).

Q. What are the responsibilities of your department?

A. It is responsible for the planning and development of the distribution system for Hawaiian Electric, and generation planning, transmission planning, renewable energy planning and integration, and system protection functions for Hawaiian Electric (Oahu), and its subsidiaries, Maui Electric Company, Ltd. (Maui, Lanai, and Molokai) and Hawai'i Electric Light Company, Inc. (Big Island). The department develops generation and transmission resource plans for these islands, with increased focus on the expansion of renewable energy resources, and the development of the distribution system and system protection schemes to safely and reliably meet changing customer needs. The department is also responsible for major projects and initiatives across all three companies, including its advanced meter infrastructure project and smart grid initiative, and Hawaiian Electric's planning activities related to the integration of large-scale wind energy resources located on the islands of Lanai and Molokai via a proposed undersea cable system to Oahu.

Q. Are the positions in the department newly created as well?

A. None of the positions are new since the 2009 rate case update was filed, and all positions were in existence at the time the department was created in March 2009.

Q. Please explain.

A. The System Integration Department consists of several existing divisions and offices from the Power Supply, Energy Delivery and Energy Solutions process areas.

Q. What divisions or positions transferred over from the Power Supply process area to the new System Integration Department?

A. The existing Administration, Generation Planning, and Transmission Planning Divisions, and the then newly formed Renewable Energy Planning Division, all of which were within the System Planning Department at the time of the March 2009 reorganization, came over from the Power Supply process area. The four new positions in the Renewable Energy Planning Division were discussed in the 2009 rate case update (refer to HECO T-7 Rate Case Update, pages 28-32) and will be explained more fully below. Of note, as part of the March 2009 reorganization, the Competitive Bidding Division was moved from the System Planning Department to the Resource Acquisition Department. (Refer to HECO ST-15D.) In addition, a Manager of Renewable Integration from the Office of the Vice President, Power Supply also transferred to the new System Integration Department. As described in HECO T-7, pages 46-47, this position was added in 2008 to direct the development of performance standards and interconnection requirements for renewable projects on Oahu. The description for this Manager-Renewable Integration was provided in HECO-721.

Q. What positions and divisions transferred from the Energy Delivery process area?

A. As discussed in the supplemental testimony of HECO-T-8, the System Protection section consisting of 4 employees and the Distribution Planning Division consisting of 7 employees from the Engineering Department were transferred to the newly formed Systems Integration Department.

Q. What positions transferred from the Energy Solutions process area?

A. The Advanced Metering Infrastructure ("AMI") functions were transferred from the Customer Installations Department of the Energy Solutions process area to the new System Integration Department. These functions have existed since 2007 with the installation of AMI meters. As described in HECO T-8, page 53, the Company had installed close to 7,000 meters, as of February 2008. As of the date of this filing, the number of installed AMI meters on Oahu is over 8,700. Refer to HECO T-8, pages 52-54 for additional information. On December 1, 2008, the Hawaiian Electric companies filed an application with the Commission in Docket No. 2008-0303 seeking approval of the Advanced Meter Infrastructure Project and requested to commit capital funds, to defer and amortize software development costs, to begin installation of meters and implement time-of-use rates, for accounting and ratemaking treatment, and other matters.

Q. What is the present composition of the AMI Division in the System Integration Department?

A. As described in response to CA-IR-217, the staffing plan for the AMI Division for the 2009 test year consists of the following six staff positions: one AMI Director, one AMI Project Manager, one AMI Systems Administrator, one AMI Project Engineer, and two AMI Systems Engineers. All six positions in the AMI Division of the System Integration Department are staffed (four positions are presently filled and job offers for the remaining two positions have been accepted by qualified candidates) and are essential to effective AMI implementation in Hawaii.

<u>HCEI-Related Positions in the System Integration Department</u>

Q. Are there any new "HCEI-related" positions in your organization that were identified in the HECO T-15 Rate Case Update.?

A. Yes. There are four positions, all residing in the Renewable Energy Planning Division:

- A Director, Renewable Energy Planning Division
- A Senior Renewable Energy Engineer
- Two Renewable Energy Engineers

(Refer to HECO T-15 Rate Case Update, Item #16, pages 10-11; HECO T-7 Rate Case Update, pages 28-32.)

All four new positions have been hired.

Q. Are they positions that the Commission ordered Hawaiian Electric to remove in Section II.1.(b) in the Interim Decision and Order ("ID&O") of Docket No. 2008-0083?

A. Yes. However, they lead many critical functions and initiatives directly resulting from the Company's commitment to and activities in renewable energy resource planning and implementation, a commitment which pre-exists the HCEI Agreement.

Q. Please explain the function of the new Renewable Energy Planning Division.

A. As stated in the HECO T-7 Update at page 29, "the new Renewable Energy Planning Division will establish dedicated technical capabilities and focused leadership to direct a wide range of in-house resources and leverage external resources as needed to analyze the impact of new renewable energy projects on the utility systems and achieve their timely and cost-effective integration. The new division's primary responsibility will be to lead the development of appropriate strategies, methods, plans, and policies to achieve successful integration of renewable energy projects for HECO, HELCO and MECO."

To better accommodate the diverse island indigenous renewable resources and best align our current utility assets, the REPD staff is spearheading a number of renewable resource characterization and analysis work necessary to transform current electrical infrastructure and controls to complement the unique nature of various renewable resources. REPD work efforts span traditional utility transmission and generation planning to also include strategic partnering and funding activities including American Recovery and Reinvestment Act ("ARRA") stimulus applications. This new division is dedicated to enhancing traditional utility planning capabilities to address real-time operational challenges for accommodating the unique nature of intermittent renewable technologies. I have prepared a summary of REPD strategic work areas with specific examples of efforts needed to accommodate renewable resources. Please refer to HECO-S-15C01 of my Supplemental Testimony.

Q. Why is it important for Hawaiian Electric undertake the work now needed to meet its HCEI Energy Agreement commitments and the requirements of Hawaii Renewable Portfolio Standards law?

A. The State of Hawaii's clean energy policy strongly mandates and promotes the use of Hawaii's renewable energy resources, as evidenced by the Legislature's recognition in 2007 that "[p]rogressive energy policy-making at the state level is one of the most important issues on the current legislative agenda." Act 177, Haw. Sess. L. 2007. In furtherance of this agenda, the 2009 Legislature passed a number of renewable energy bills, including Act 155, which among other things, increases electric utilities' 2020 RPS requirement from 20% to 25%, and adds a new 40% requirement for the year 2030. In addition, whereas prior to January 1, 2015, only 50% of a utility's RPS needed to be met by "electrical generation using renewable energy as the source", after January 1, 2015, a utility's entire RPS will need to be met by renewable generation, and "electrical energy savings" (i.e., energy efficiency) will no longer count toward RPS requirements.

In order to achieve these aggressive new RPS goals, Hawaiian Electric must take advantage of wind power. Wind power is a commercially proven source of renewable energy whose harnessing technologies are available today. While the potential for developing wind generation may be limited on Oahu, wind power is an abundant resource on the neighbor islands, with combined resource potential across the State estimated to be in excess of 1,000 MW. Thus, the incorporation of large amounts of wind power into Hawaiian Electric's electrical system presents a promising opportunity to significantly advance the development and use of renewable energy on Oahu.

Enabling substantially greater use of wind power on Oahu will require the transmission of electricity produced by wind power on the neighbor islands to Oahu via an undersea cable system. However, facilitating a future in which the abundant, sustainable and indigenous wind resources of our islands supply a significant portion of the total energy demand on Oahu requires extensive engineering, technical and financial studies and analyses to identify integration and performance requirements, undersea cable system requirements, and Hawaiian Electric system modifications, infrastructure additions and operating solutions to be conducted in a comprehensive but expedited manner.

The study effort is substantial (in terms of time, effort and resources), and the cost of the study effort as scoped to date that the Company is funding is significant (estimated at $6,258,000). The cost of <u>not</u> planning, however, would be greater. Moreover, the cost of failing to meet the objectives of state policy – which would leave Oahu's electricity infrastructure tied to oil – would be far greater.

Q. Are efforts already underway regarding integrating more renewable energy from wind into Hawaiian Electric's system?

A. Yes. Hawaiian Electric and the State of Hawaii already have launched the extensive planning and study efforts necessary to initiate the Wind Projects. The Company is currently leading or supporting three major components critical for Big Wind Project implementation. These components include the cable study/options, Oahu electrical infrastructure system impact studies and wind plant infrastructure and integration studies. Hawaiian Electric also provides critical operational support and engineering design/routing necessary to maintain transmission reliability and system integrity for the Oahu electrical infrastructure (the compatibility of which is critical to the other major components of the Big Wind Project).

The best way to maximize the amount of cost-effective, intermittent renewable energy that can be reliably integrated into the Hawaiian Electric Companies' systems is to proceed expeditiously, but at the same time in an informed manner. Proceeding in an informed manner, however, entails the development of a detailed technical and economic model of the existing electrical infrastructure of the grid. Such modeling requires that up-front technical analyses be conducted to provide information regarding the impacts on system power flows, voltage, and frequency from the intermittent generation scenarios proposed and the associated mitigating measures that are needed for the system to accommodate the intermittent generation.

A more complete discussion of the need to proceed with work now to prepare for integration of renewable energy is contained in Hawaiian Electric's

Application For Approval of Recovery of Big Wind Implementation Studies Costs through the Renewable Energy Infrastructure Program Surcharge filed with the Commission on July 17, 2009.

Q. To summarize, why are the positions in the System Integration Department created since the 2007 rate case settlement necessary and important?

A. Hawaiian Electric must undertake an unprecedented amount of planning and studies now in order to implement the integration of renewable energy in a timely manner. Much of that work has already begun and preceded the HCEI Energy Agreement, and much of that work does not require Commission approval because it involves acquiring basic knowledge that will form the foundation of many different facets of the future renewable energy infrastructure. As noted in HECO's T-7 Rate Case Update, pages 8-9, many of the component studies of the overall Implementation Studies are multi-year efforts and involve strategic efforts with accomplished technical representatives from the Hawaii Natural Energy Institute ("HNEI"), the National Renewable Energy Laboratory ("NREL"), and the Lawrence Livermore National Laboratory ("LLNL"). Without the new positions in the System Integration Department, the necessary continuation and expansion of this important work will be impaired.

Q. Does this conclude your testimony?

A. Yes, it does.

Hawaiian Electric Company, Inc.

LEON R. ROOSE

EDUCATIONAL BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS:	Hawaiian Electric Company, Inc. 820 Ward Avenue P. O. Box 2750 Honolulu, HI 96840
CURRENT POSITION:	Manager, System Integration Department (formerly, System Planning Department)
YEARS OF SERVICE:	16 Years
EDUCATION:	Juris Doctor – William S. Richardson School of Law University of Hawaii, Manoa (1990 – 1993) Bachelor of Science – Electrical Engineering University of Hawaii, Manoa (1983 – 1988)
EXPERIENCE:	January 2007 – Present Manager, System Integration Department (formerly, System Planning Department) HECO September 2004 – January 2007 Manager, Power Supply Services Department HECO October 1996 – September 2004 Associate General Counsel, Legal Department HECO February 1996 – October 1996 Planning Engineer, Planning & Engineering Department HECO

EXPERIENCE:	(continued)
	June 1993 – February 1996 Attorney, Damon Key Bocken Leong Kupchak Practice focused in business, corporate, intellectual and real property law; general civil litigation
	May 1990 – January 1992 Analyst Temp, Rate and Regulatory Affairs Department HECO
	June 1988 – August 1990 Designer I, System Planning Department HECO
	1986- 1988 Engineering Analyst Naval Ocean Systems Center
OTHER PROFESSIONAL EXPERIENCE:	April 2008 Utility Wind Integration Group Annual Meeting and Technical workshop – Fort Worth, TX
	July 2007 Utility Wind Integration Group Annual Meeting and Technical workshop – Anchorage, AK
	June 2005 Utility Executive Course University of Idaho – Corporate Utility Training Program
TESTIMONY:	UPC Hawaii / Kaheawa Wind Power II Complaint Docket No. 2008-0021
	Competitive Bidding for New Generation Docket No. 03-0372

The HCEI Agreement and Big Wind studies

Pursuant to the Energy Agreement between HECO and the Consumer Advocate (the "HCEI Agreement"), the Hawaiian Electric Companies are committed to integrating the maximum attainable amount of wind energy on their systems.

"In order to facilitate a future in which the abundant, sustainable and indigenous wind resources of our islands supply a significant portion of the total energy demand on Oahu," the HCEI Parties committed to integrate, with the assistance of the State to accelerate the commitment, up to 400 MW of wind power into the Oahu electrical system that is produced by one or more wind farms located on either the island of Lanai or Molokai and transmitted to Oahu via undersea cable systems (the "Big Wind" projects). This commitment was made in recognition that wind power is a commercially proven source of renewable energy today that, while limited on Oahu, is abundant on the neighbor islands of Lanai and Molokai.

The HCEI Agreement provides that Hawaiian Electric is responsible for funding, constructing, operating and maintaining all land-based connections and infrastructure improvements to the existing Hawaiian Electric system up to the interconnection point located at the on-shore termination of the State owned undersea cable systems on Oahu.

The HCEI Agreement also provides that all necessary engineering, technical and financial studies and analyses to identify Big Wind project integration and performance requirements, undersea cable systems requirements, and Hawaiian Electric system modifications, infrastructure additions, and operating solutions ("Implementation Studies") will be conducted in a comprehensive but expedited manner.

Responsibilities of the Renewable Energy Planning Division

The newly formed Renewable Energy Planning Division ("REPD"), consisting of "one Director, one Senior Renewable Energy Engineer, and two Renewable Energy Engineers" (HECO T-7 Rate Case Update, Docket No. 2008-0083 ("HECO T-7 Update"), pages 28 – 29), has been actively engaged in a number of HCEI and non-HCEI activities in support of integrating renewable resources onto the Hawaiian Electric grid. Though Big Wind project activities have been a key focus of the REPD activities, it is one of a number of transformational work efforts undertaken by the Division and the Company to enhance uptake of renewable resources throughout the islands. As described on page 32 of the HECO T-7 Update, the staff in the new REPD will have responsibilities supporting HECO, HELCO and MECO. In the 2009 test year, the labor cost for the entire division is allocated between the three utilities at 50%, 25% and 25%, respectively. Of the 50% of their time that is dedicated to HECO renewable energy planning initiatives, one-half of that time is focused on HCEI activities in the form of work on the Big Wind project.

As described on page 29 of the HECO T-7 Update, "the new Renewable Energy Planning Division will establish dedicated technical capabilities and focused leadership to direct a wide range of in-house resources and leverage external resources as needed to analyze the impact of new renewable energy projects on the utility systems and achieve their timely and cost-effective integration. The new division's primary responsibility will be to lead the development of appropriate strategies, methods, plans, and policies to achieve successful integration of renewable energy projects for HECO, HELCO and MECO."

To better accommodate the diverse island indigenous renewable resources and inform the alignment of current utility assets, the REPD staff is spearheading a number of renewable resource characterization and analysis work necessary to transform current electrical infrastructure and controls to complement the unique nature of various renewable resources. REPD work efforts span traditional utility transmission and generation planning to also include strategic partnering and funding activities including ARRA Stimulus applications. This new division is dedicated to enhancing traditional utility planning capabilities to address real-time operational challenges for accommodating the unique nature of intermittent renewable technologies. REPD strategic work efforts to accommodate renewable resources include the following areas:

- Strategic Partnerships & Outreach;
- Methodologies & Evaluation Processes;
- Planning, Policies & Procedures; and
- Infrastructure & Technology Enhancements.

Highlights from these strategic areas are provided below:

STRATEGIC PARTNERSHIPS & OUTREACH

- **ARRA Stimulus Funding**
  The REPD is leading and supporting the proposal development and application for a number of ARRA federal stimulus Funding Opportunity Announcements ("FOA") for HECO and sister utilities HELCO and MECO. Proposal applications are focused on enhancing the existing grid to better accommodate renewable energy resources with upgraded system infrastructure. Proposals submitted to date include Wind Energy Integration and Pump-Storage Hydro applications seeking over $1M in federal support. Proposals seeking over $50M in ARRA funding are in development and cover a variety of areas including Smart Grid infrastructure demonstration, T&D and communication infrastructure upgrades, data awareness management and visualization, intermittency management capabilities, solar and wind characterization/forecasting and consequence/security assessments. Federal funds are aggressively being pursued to expedite transformational efforts and to minimize the impact on rate base.

  Examples: FOA Proposal Development Work

- **DE-PS36-09GO99009** – Submitted proposal entitled "Hawaii Utility Integration Initiatives (H.U.I.) to Enable Wind" for $750,000 over 2 years to begin initiatives for HECO/MECO/HELCO that begins to integrate real-time field monitored information for intermittent resources and provides advance control benefits so operators can "sense", forecast, track and reliably respond to wind variability.

- **DE-FOA-0000069** – Submitted proposal entitled Pumped Storage Hydro for Renewable Energy Integration (PUSH4Renewable) for $400,000 over 9 months to complement MECO's pumped hydro storage RFP solicitation.

- **DE-FOA-0000085** – Working on a $3.6 M proposal over a 5 year period to develop monitoring and analysis capabilities for assessing the impact of high penetration PV solar for HECO/MECO/HELCO at the distribution grid levels. Power delivery via the distribution level must also be improved to enhance and support management of distributed generation and other local resources to achieve overall system reliability.

- **DE-FOA-0000058** – Working on a number of proposals topics (3) in the Small Grants category ($1M to less than $20M spanning 2 to 3yrs) pursuant to the Investment Grant Programs to enable Smart Grids. Proposals all include strong industry partnerships and focus on leveraging HECO/MECO/HELCO investments as cost share to attract federal support to build up island infrastructure for the distribution system, communication infrastructure and information management of renewable data. Scope definition is complete and proposal writing is underway.

- **DE-FOA-0000036** – Working on a number of proposals (2) in the Smart Grid Demonstration Program ranging from $5M to $60M spanning 3 to 5 yrs. This proposal category has required additional resources to form industrial partnerships and secure cost share contribution from all parties. Definition of scope for a Smart Grid proposal for HECO and a Storage Demonstration proposal for MECO are in progress.

- **Synergistic Alliances and Resource Development**
  The REPD is directly involved in developing and supporting strategic partnerships with federal, military, states, academia and industry to enhance our ability to support the transformational changes being pursued (e.g. cost share for studies, synergistic alliances, and new workforce pipeline). As an example, critical elements of the Big Wind Implementation Studies are currently being funded through the strategic partnerships with HNEI, EPRI and U.S. DOE to provide direct

dollars, technical support and technical advisory and outreach resources. Close coordination and active involvement with our partners consumes a majority of time and energy in this area; however, our technical engagement is critical in ensuring system reliability and integrity for the customers. These strategic partnerships are critical in the long run as ARRA and other shorter-term funding resources will not sustain the level of support and technical resources necessary to enable the future grid. Technical outreach (e.g. conferences and meetings) activities are also a vital component in attracting funding resources to address needs to accommodate renewable energy resources, creating awareness of our needs and national needs, and supporting the education of the next generation of workforce.

Examples:

- HNEI cost share for GE Phase II development efforts, and cost share for potential travel to investigate promising storage technologies.
- Supporting technical transfer, education and training to the University of Hawaii, Manoa on a federally funded opportunity to enhance Renewable Energy Programs to develop a future energy-savvy workforce in Hawaii.
- Supporting HECO efforts and meetings with military renewable energy planners.
- Dedicated in-house capability to actively support and create funding opportunities with industry and other utilities (e.g. SMUD, PG&E, SCE, BPA, Shasta County) to develop analytical tools and capabilities in wind and solar forecasting, electric system modeling and other visualization needs.

METHODOLOGIES & EVALUATION PROCESS

- **CESP Locational Value Resource Mapping and Process Development.** Supporting the CESP Strategic Team, the REPD has been tasked with leading the development of a consistent and transparent process for creating the locational value map ("LVM") for HECO and sister utilities HELCO and MECO. The LVM effort is seen as a process for understanding current utilization and impact of distributed renewable energy resources ("Renewable DER") on the islands and enabling the future forecasting and planned expansion of new Renewable DER potential. The REPD is working to develop the analytical modeling and renewable resource portfolio that can enhance the existing T&D infrastructure, thus maximizing the value of distributed generation locations throughout the islands.

  Examples:

  - Coordinating meetings are in progress with HECO mapping services and Distribution Planning to develop a baseline of existing Net Metering and distributed generation penetration levels for HECO/MECO/HELCO.
  - Developing a consistent process to model future system impacts due to more distributed generation and conduct trade-off studies to assess the

locational value for expansion to support growth. Activity is planned with industry model developers to enhance our tools.

- **Support for Power Purchase Agreements.**
This work effort focuses on understanding and assessing the effect of new renewable energy resources on the utility grid, ensuring the safe and reliable operation of the overall system and advising senior management and the utility negotiating team on power purchase contract terms and strategies. The REPD is providing new staff, data and modeling resources to expand the traditional generation and transmission planning efforts undertaken for the Power Purchase Agreement ("PPA") process for HECO, HELCO and MECO. Support includes review of existing system data, development of performance standards, interconnection requirements, and protection schemes for renewable generators, and assistance in ensuring project compliance with interconnection requirements and administration of power purchase contract terms. In support of the Resource Acquisition Department, new agreement models are also being explored to maximize the uptake of renewable energy through various programs including Net Energy Metering and Feed-in-Tariff which all require additional renewable resource integration data.

PLANNING, POLICIES & PROCEDURES

- **Renewable Resource Monitoring and Characterization ("R-DATA").**
The REPD is leading a strategic initiative R-DATA to deploy renewable resource monitoring, characterization capabilities and modeling tools to support traditional transmission, generation and operational planning capabilities for HECO and sister utilities HELCO and MECO. Integration of renewable resources requires proper characterization of the resources in terms of quality and quantity. A major challenge for utilities around the world is the lack of appropriate high resolution (second-to-second) renewable resource data and monitoring infrastructure necessary to capture the information for planning needs. Due to the intermittent nature of key island renewable resources like wind and solar, new data forecasting tools, models and control strategies unique to the islands need to be developed and used to transform the traditional utility planning and operational process to a new paradigm. The REPD is currently working with outside wind energy forecasting vendors, national laboratories and industry consultants to (a) deploy solar and wind data monitoring equipment, (b) to build the data sets necessary for planning and modeling, and (c) to develop the forecasting and visualization tools and new procedures needed to operate the future grid.

  Examples:
  - Developing an organized database of solar, wind and other renewable data for HECO/MECO/HELCO for resource analysis and planning use

  - Downloading of essential system parameters necessary to complement the renewable resource data
  - Coordinated deployment of 5 solar monitoring units to begin collecting high resolution (2-sec) solar data to support planning studies and modeling needs.

- **Renewable Planning and Operations Support.**
The REPD brings resources to begin filling the gap between traditional utility (transmission, distribution and generation) planning and real-time operations. As more intermittent renewable resources are brought online, the traditional annual to daily planning horizon is drastically reduced to the hourly and intra-hour for these types of variable generating resources. In order to address the unique operational challenges of these resources, the current planning and operational practices needs to be augmented with new data, tools and/or modified procedures. Dedicated division staff supports a number of traditional utility planning areas but must also begin to infuse the operational perspectives and needs for real-time resource availability data, visualization and awareness in the control room that currently are outside of traditional utility planning practices. The REPD staff is working closely with mainland utilities and industry technology providers to close this gap and address renewable planning, mitigation strategies and real-time operating needs.

  Examples:
  - Investigating database and visualization technologies for rendering expansive datasets which exceed current in house tools. (e.g., worked with IT to install Google Maps-based software to visually connect resources to infrastructure. Rendering capability now available to planning division.)
  - REPD staff directly engaged in the review of emerging industry tools/techniques, ramp event forecasting tools and real-time "sensing" capability for wind and solar through involvement with other mainland utilities and grid operators (BPA, SCE, CaISO).

INFRASTRUCTURE & TECHNOLOGY ENHANCEMENTS

- **Support for Smart Grid**
The REPD is supporting a major initiative of the Hawaiian Electric Companies to upgrade the existing electrical infrastructure to a smarter more integrated grid. The enhancements involve a number of major areas including new generation resources, new distribution resources, controls and protection strategies, visualization and operations as well as key security enhancements. The REPD staff is providing key support in the areas of renewable planning, communication and visualization needs for forecasting renewable resources, performance criteria for utility-scale and

distributed renewable resources and the risk assessments associated with staging the change to a future smarter grid.

Examples:

- Working on the Smart Grid Task Force and evaluating transformational needs for the HECO/MECO/HELCO systems
- Supporting IT Security resources to evaluate critical infrastructure needs and interoperability risks and link with national resources to aid Company activities.

- **Big Wind Implementation Studies**
The Big Wind Implementation Studies are currently looking at development of new planning models and tools to simulate and assess the impact of interconnecting renewable generation resources between the island grids. The REPD has direct responsibility for managing the Big Wind project planning studies and coordinating the deliverables from various lead departments. The Division also has support responsibilities to pull together the various departments working on Big Wind Implementation Studies to identify and frame the system capabilities, enhancements and new technologies needs to support interconnecting the grids. As a number of the technical studies for implementing the integration of the Big Wind projects are funded by state and national resources, the REPD support activities also include coordinating the outside vendor/national laboratory activities, interfacing with the state leads, and ensuring timely reporting of HECO milestones.

SUPPLEMENTAL TESTIMONY OF SCOTT W. H. SEU

MANAGER
RESOURCE ACQUISITION
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Employee Count

INTRODUCTION

Q. Please state your name and business address.

A. My name is Scott W. H. Seu and my business address is 220 South King Street, 14th Floor, Honolulu, Hawaii 96813.

Q. By whom are you employed and in what capacity?

A. I am the Manager of Resource Acquisition for Hawaiian Electric Company, Inc. ("Hawaiian Electric" or "Company"). My experience and educational background are listed in HECO S-15D00.

Q. What is the focus of your supplemental testimony?

A. My supplemental testimony covers the Resource Acquisition Department and will support the need for new positions in this department created since the 2007 rate case test year settlement.

The New Resource Acquisition Department

Q. What is the Resource Acquisition Department?

A. As mentioned in HECO ST-7 and HECO ST-15, it is a department created under the Company's new Clean Energy Organization. It is part of the Company's effort to organizationally realign and add resources to better manage the workload in order to meet corporate goals to integrate more power generated from clean and renewable resources, including goals established through Hawaii's Renewable Portfolio Standards and the Hawaii Clean Energy Initiative process.

Q. What are the responsibilities of this department?

A. The Resource Acquisition Department administers competitive bidding initiatives pursuant to the Commission's Framework for Competitive Bidding for new generation, contracts for energy via power purchase agreements and administers the agreements, provides project management for the development of innovative energy projects and programs including distributed generation and distributed energy storage, and coordinates the company's research and development ("R&D") activities including its membership in the Electric Power Research Institute ("EPRI"). The Resource Acquisition Department consists of the following divisions, in addition to an administrative section: Energy Analysis, Distributed Energy Development, Distributed Technology Applications, Renewable Technology, Competitive Bidding, Power Purchase Administration, and Power Purchase Negotiation.

Q. Are the positions in the department newly created?

A. No. All 25 positions (2009 test year average) in the department come from other process areas. None are new since the 2009 rate case update was filed, and all but four have existed since the 2007 rate case test year settlement.

Q. Please explain.

A. The Resource Acquisition Department was created from pre-existing organizations under the March 2009 reorganization. The department manager, secretary, and budget/program analyst came from the administrative section of the former Hawaiian Electric Energy Projects Department, which was discussed in HECO T-15.

An Energy Analysis position from the former Energy Solutions process area was moved to the Resource Acquisition Department. It is primarily responsible for conducting evaluations of new renewable energy business opportunities, and providing business model analysis support to the department.

The Distributed Energy Development and Distributed Technology Applications divisions of the Resource Acquisition Department formerly constituted the bulk of the Energy Projects Department. The Distributed Energy

Development Division focuses on developing distributed generation ("DG") projects. Their current projects include the Airport Dispatchable Standby Generation project, the Manele Bay Combined Heat and Power project, evaluating the conversion of HECO's substation DG units to biofuels, and evaluating other DG projects to serve utility and customer needs, such as at military bases. The Distributed Technology Applications Division focuses on the evaluation and development of utility projects that employ innovative distributed energy technologies such as battery energy storage systems, flywheels and distributed renewables such as photovoltaics. The Distributed Technology Applications Division is currently overseeing the Company's Archer Substation PV project, evaluating battery energy storage systems, providing project management services to MECO for a Maui smart grid program, and has responsibility for the proposed PV Host program. These two divisions are primarily in-house project development and project management groups, capable of formulating new projects and programs on their own initiative or in support of other areas such as the Renewable Energy Planning Division of the System Integration Department, and designing and developing them to implementation.

The Renewable Technology Division is the Technology Division of the Energy Solutions process area that was discussed in HECO T-15. The Renewable Technology Department is responsible for monitoring and assessing the status of new developing technologies, primarily renewable energy generating resources. This organization also has responsibility for administering the Company's EPRI membership, and helps other departments and divisions in the Company in coordinating their R&D activities.

The Competitive Bidding Division, originally from the System Planning

Department in the Power Supply process area is now part of the Resource Acquisition Department. They are responsible for managing competitive bids for new generation for the Hawaiian Electric Companies, pursuant to the Commission's Framework for Competitive Bidding. This division also has responsibility for competitive procurement of resources not subject to the Framework for Competitive Bidding, where the Company determines that competitive procurement is desirable.

The Power Purchase Administration Division, originally from the Power Supply Services Department (described in HECO T-7, pages 70-73) of the Power Supply process area, is responsible for administering the power purchase agreements ("PPA") of the company. Administration of PPAs includes the tasks of processing and paying monthly invoices from independent power producers ("IPP"), coordinating IPP maintenance schedules, and resolving all issues that arise between IPPs and the Company.

The Power Purchase Negotiation Division from the Power Supply Service Department of the Power Supply process area was also discussed in HECO T-7 Rate Case Update, pages 22-26. This division is responsible for processing IPP proposals for new generation, including those that arise out of the Framework for Competitive Bidding, coordinating technical and financial reviews of the proposals, and negotiating and executing PPAs. At this time, the Power Purchase Negotiation Division is still being staffed, and PPA negotiation duties are being handled in joint fashion with the Power Purchase Administration Division.

<u>New Positions in the Resource Acquisition Department</u>

Q. What are the new positions since the 2007 rate case test year settlement?

A. The four new positions are:

- Two Senior Technical Services Engineers in the former Energy Projects Department (refer to HECO T-15 rate case update, pages 6-7), one of which is now assigned to the Distributed Energy Development Division and the other to the Distributed Technology Applications Division;
- A Director of Power Purchase Negotiation and a Power Purchase Negotiator in the Power Purchase Negotiation Division (refer to HECO T-15 rate case update, pages 10; HECO T-7 rate case update, pages 22-26).

Q. What is the status of filling these positions?

A. The Senior Technical Services Engineer for the Distributed Technology Applications Division and the Power Purchase Negotiator have been hired. Recruiting is underway for the Director of Power Purchase Negotiation position. Recruiting for the Senior Technical Services Engineer for the Distributed Energy Development Division is planned to begin by the end of July 2009.

Q. Please explain the functions performed by the Senior Technical Services Engineer in the Distributed Technology Applications Division, and why this position is needed.

A. This Senior Technical Services Engineer position is described in HECO T-15 Rate Case Update, page 6, item 8 and HECO T-7 Rate Case Update, pages 37-38. The person is currently working full-time supporting the renewable energy projects and initiatives of the Distributed Technology Applications Division. Those projects include a strategic partnership with the Department of Hawaiian Homelands exploring innovative distributed technologies, Maui and Oahu battery energy storage projects, a Department of Energy-funded Maui smart grid project, and further development of utility-sited PV.

Q. What percentage of time would this position work on HCEI-related activities?

A. The activities described above are all related to distributed renewable energy projects that the Company has been engaged with prior to HCEI, or as in the case of the Department of Hawaiian Homelands initiative, is separate and apart from HCEI. The Company's proposed PV Host program is a specific HCEI initiative that the position would support 50% of the time, if the program is approved by the Commission. The 50% estimate of time for PV Host is based on the fact that the program, if approved, will involve numerous site visits and project management. The remaining 50% will be spent on the already on-going projects and initiatives described above.

Q. Please explain the functions to be performed by the second Senior Technical Services Engineer position, in the Distributed Energy Development Division.

A. The responsibilities described for the second Senior Technical Services Engineer on pages 6-7 of the HECO T-15 Rate Case Update, are as follows:

> "…assist with development of distributed generation ("DG") projects, evaluate DG technologies (whether combustion turbine or large diesel-generators), prepare bid drawings and specifications, conduct bid evaluations and construction monitoring, implement startup, and evaluate operations of the DG units. DG units will provide additional quick start generating capacity on Oahu to allow integration of intermittent wind energy into the Hawaiian Electric system. This engineer will work on the development of DG units at a number of potential sites, including at military bases. The Naval Facilities Engineering Command intends to issue one or more requests for proposals seeking the development of DG units on several Oahu military bases. Hawaiian Electric plans to

> participate in these processes and anticipates that a formal proposal will be submitted for at least one military DG project in mid-2009."

The Hawaiian Electric Companies have been developing DG projects since the 1990s, when the first remotely located DG units were placed in service on the HELCO system to serve peak capacity needs. This has continued to the present day with Hawaiian Electric Company's substation DG units installed in 2005-2007, the Manele CHP project which is under construction, and the Airport dispatchable standby generation ("DSG") project, all projects which were developed by the former Energy Projects Department.

Hawaiian Electric plans to engage with additional large customers about developing DSG facilities, subject to successful resolution of accounting and ratemaking issues raised in the Commission's recent decision and order for the Airport DSG project. Hawaiian Electric also intends to conduct further engineering and analysis of the requirements to keep the 30 MW of temporary substation DG in long term service, and to convert the units to biofuels. The substation DG units provide valuable system operational and economic benefit given their low heat rates and quick starting capability.

Hawaiian Electric has also been engaged with the Department of Defense ("DOD") about potential development of Company-owned DG units on Oahu military bases since June 2005, when the Company and the military commands agreed to conduct an evaluation of DG opportunities at Oahu DOD sites. This effort culminated in the execution of a memorandum of understanding ("MOU") in mid-2006 between the Company and the Navy to cooperate in further assessment of DG development at Pearl Harbor. Since then, Hawaiian Electric has continued to conduct feasibility analyses and preliminary engineering of DG at Pearl Harbor and Schofield Barracks. The DOD has issued several requests for information from entities with experience developing, constructing, operating, and maintaining renewable-fueled power plants. Hawaiian Electric fully intends to continue engaging with the DOD about development of DG.

Q. What percentage of time would this position work on HCEI-related activities?

A. The Senior Technical Services Engineer in the Distributed Energy Development Division will support all of the above DG-related activities, which with the exception of the potential biofueling of HECO's substation DG units, were all in progress prior to HCEI. The DG biofueling effort, once fully underway, would represent at most 1/3 of the engineer's time. Thus, this person would be 66% non-HCEI, and 34% HCEI if biofueling of DGs was to proceed.

Q. Please describe the functions performed by the Director of Power Purchase Negotiation and the Power Purchase Negotiator, and their relationship to the HCEI Energy Agreement.

A. These positions are described in HECO T-15 Rate Case Update, page 10, item 14 and HECO T-7 Rate Case Update, page 22-26. These positions are directly involved in the negotiation and administration of PPAs and amendments, all of which are ongoing, or would be pursued irrespective of the Energy Agreement. Such PPA proposals include those submitted by developers in response to competitive solicitations issued by the Company pursuant to the Framework for Competitive Bidding, proposals submitted by developers for projects not subject to the Framework for Competitive Bidding, and projects grandfathered from the Framework. The overwhelming majority of the agreements/amendments is and will continue to be for renewable energy projects, especially as the Company seeks to meet its Renewable Portfolio Standard obligations.

PPAs that may arise as a direct result of the HCEI Energy Agreement include those that may come from a feed-in tariff. If a feed-in tariff is established, the Power Purchase Negotiation Division would provide administrative support in its implementation. However, Hawaiian Electric has not yet determined the resource needs for implementation of a feed-in tariff, given that such resource requirements will be highly dependent on the scale and scope of the tariff which are still to be determined in the ongoing feed-in tariff proceeding. Hawaiian Electric and the Consumer Advocate have proposed that a feed-in tariff be established for distributed renewable energy projects, leaving the Framework for Competitive Bidding in place for larger projects. If a feed-in tariff is established that comports with the feed-in tariff proposal of the Company and Consumer Advocate, it is estimated that the two new positions would devote no more than 25% of their time to such PPAs, with the remaining 75% of their time spent on IPP proposals not directly related to the HCEI Energy Agreement.

Q. Would you describe the four new positions as "HCEI-related" positions?

A. Only to the degree that they would support some specific HCEI-related programs and projects. As described above, much of their work can be characterized as supporting renewable energy related activities of the Company that would be pursued, or were being pursued, irrespective of the HCEI Energy Agreement.

Q. To summarize, why are the positions in the Resource Acquisition Department created since the 2007 rate case settlement necessary and important?

A. Hawaiian Electric must undertake an unprecedented amount of project development and power purchase agreement work now in order to add renewable energy in a timely manner. Much of that work has already begun and preceded the HCEI Energy Agreement. Without the new positions, this important work will be impaired.

Q. Does this conclude your testimony?

A. Yes, it does.

SCOTT W. H. SEU
EDUCATIONAL BACKGROUND & EXPERIENCE

BUSINESS ADDRESS:	Hawaiian Electric Company, Inc. P. O. Box 2750 Honolulu, Hawaii 96840
CURRENT POSITION:	Manager, Resource Acquisition Department Hawaiian Electric Company, Inc. Honolulu, Hawaii.
PRIOR EXPERIENCE:	
2004 – 2008	Manager, Energy Projects Department, Hawaiian Electric Company.
2003 – 2004	Manager, Customer Installations Department, Hawaiian Electric Company.
1998 - 2002	Manager, Environmental Department, Hawaiian Electric Company.
1997 - 1998	Principal Environmental Scientist, Environmental Department, Hawaiian Electric Company.
1993 - 1996	Senior Environmental Scientist, Environmental Department, Hawaiian Electric Company.
1991 - 1993	Staff Environmental Engineer, Acurex Environmental Corporation, Mountain View, California.
1989-1991	English Teacher, Sichuan University, China.
1988-1989	Mechanical Engineer, Westinghouse Electric Corporation, Sunnyvale, California.
EDUCATION:	Stanford University, Stanford, California. MS Mechanical Engineering, 1988. BS Mechanical Engineering, 1987.
PROFESSIONAL REGISTRATION:	Professional Engineer, mechanical branch (license no. 8844), State of Hawaii.

SUPPLEMENTAL TESTIMONY OF
LON K. OKADA

MANAGER
CORPORATE TAXES
HAWAIIAN ELECTRIC INDUSTRIES, INC.

Subject: Accumulated Deferred Income Taxes

INTRODUCTION

Q. Please state your name and business address.

A. My name is Lon K. Okada and my business address is 900 Richards Street, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am employed by Hawaiian Electric Industries, Inc. ("HEI") and my title is Manager of Corporate Taxes. My educational background and work experience are listed in HECO-1600.

Q. Have you previously testified in these proceedings?

A. Yes, I submitted written direct testimony, exhibits and supporting workpapers as HECO T-16.

Q. What is the nature and scope of your current supplemental testimony?

A. My supplemental testimony addresses concerns raised by the Commission in its *Interim Decision and Order* ("Interim D&O"), issued on July 2, 2009 in this docket, related to Hawaiian Electric Company, Inc.'s ("HECO" or "Company") Accumulated Deferred Income Taxes ("ADIT").

Q What specific aspects of ADIT will you address?

A. I will address three specific items in response to the Interim D&O.

First, I will address the Commission's determination in Section II.2.(a) of the Interim D&O that interim rates should reflect an adjustment to exclude any costs or rate base additions associated with the Campbell Industrial Park Combustion Turbine Unit ("CT-1"). Although the Company disagrees, if CT-1 is ultimately excluded from rate base, the ADIT associated with CT-1 also should be excluded.

My testimony substantiates the amount of ADIT related to CT-1 in the test year rate base.

Second, I will address the Commission's request in Section IV.(c).1 of the Interim D&O for clarification and support for the calculation of the ADIT adjustments related to removal of the Company's Customer Information System ("CIS") project costs from rate base.

Third, I will address the Commission's request in Section IV.(c).2 of the Interim D&O for workpapers showing the calculations underlying the book depreciation adjustment in the ADIT calculation.

CT-1

Q. How does HECO substantiate the ADIT associated with the CT-1 project included in rate base for the 2009 test year?

A. The testimony and exhibits as revised for the Rate Case Update in HECO T-16; page 73 of Exhibit 1 to the Stipulated Settlement Letter filed on May 15, 2009; and the Statement of Probable Entitlement filed on May 18, 2009, supported the test year estimates of the ADIT associated with CT-1. This estimate essentially represents the tax effect of the first year Modified Accelerated Cost Recovery System ("MACRS") depreciation and the bonus depreciation (federal only) on the tax basis of CT-1. The book depreciation on CT-1 was not a book tax difference for the test year, as book depreciation begins in the year subsequent to the year an asset is placed into service. See HECO S-1601, page 2 for details of the calculation.

Q. What other tax related items are associated with the CT-1 project?

A. In addition to the CT-1 project costs, HECO is required to provide a tax gross up on the equity portion of the allowance for funds used during construction ("AFUDC"), charged to the CT-1 project. This tax gross up is charged to the SFAS 109 Regulatory Asset account under construction work in progress ("CWIP") Equity Ongoing (#18673400). An equal and offsetting amount of ADIT must be provided as required by SFAS 109, accounting for income taxes. This is explained in my testimony T-16, pages 17 and 18. In addition, ADIT is provided on the tax capitalized interest ("TCI") related to the CT-1 project costs.

Q. How does the exclusion of CT-1 impact the rate base treatment of the related CWIP Equity Ongoing regulatory asset and ADIT associated with the AFUDC and TCI?

A. Based on the Interim D&O and the agreement among HECO, the Consumer Advocate and the Department of Defense in Docket No. 2006-0386 (HECO's 2007 test year rate case), all these items should remain in rate base. In Docket No. 2006-0386, it was determined that rate base should include the ADIT provided on AFUDC and TCI, irrespective of whether the related project costs have been placed in service. It was also determined that the SFAS 109 regulatory asset representing the tax gross up on AFUDC equity (CWIP Equity Ongoing) should likewise remain in rate base in the interest of consistency. Consequently, no adjustment to rate base is required for these three items as a result of the exclusion of CT-1 project costs.

Q. How much ADIT is associated with the CT-1 project included in rate base?

A. The total ADIT associated with CT-1 is calculated to be $4,518,000 and the impact on average rate base was $2,259,000. The exclusion of the ADIT associated with CT-1 has the effect of decreasing ADIT (increasing rate base). See HECO S-1601, page 1 for a summary of total ADIT with and without the ADIT associated with CT-1.

CIS

Q. What is the source of the ADIT adjustment of $306,000 relating to the CIS removal?

A. It is included in the response to CA-IR-396, Attachment 4, page 1 and 4. Page 1 is a revision of a schedule that was submitted on April 3, 2009 with the response to CA-IR-323, Attachment 1, page 1. See HECO S-1601 page 3

Q. What does the $306,000 represent?

A. The $306,000 is the change in the average ADIT balance in rate base associated with the CIS project.

Q. What does the $608,000 represent?

A. The $608,000 is the change in the 2009 ADIT ending balance in rate base for the CIS project

Q. Why is the ADIT associated with the CIS project still included in rate base when the CIS project costs have been removed from rate base?

A. This ADIT was provided as a result of the deductibility of the internal development costs associated with the CIS project. The Company receives a tax deduction as these costs are incurred. On the other hand, for purposes of book and regulatory treatment, these costs are capitalized and amortized (and recovered in rates) over the project's useful life. This book tax difference should therefore be provided and included in rate base since the tax benefit of the current deduction is received by the Company.

Q. Why isn't the average change half of the $608,000?

A. There was a change of $3,000 to the actual deferred tax for CIS in 2008. Therefore, the average change would be $306,000 (($3,000 + $608,000) / 2).

Q. Is the $608,000 the proper amount to use on page 73 of Exhibit 1 of the Settlement Agreement?

A. Yes.

Book Depreciation

Q. Why was there a change in ADIT related to a reduction of book depreciation expense?

A. The change in book depreciation expense is explained in Mr. Tamashiro's supplemental testimony in ST-14. As a result of this change, the associated ADIT was adjusted accordingly, increasing ADIT provided in 2009 by $427,000 ($1,098,000 x 38.91%). The impact on average rate base was a decrease of 50% of $427,000, or $214,000. For purposes of calculating ADIT, the difference between book depreciation and tax depreciation is a temporary difference for which ADIT must be provided. The change in book depreciation expense necessitated this adjustment.

Q. Does this conclude your supplemental testimony?

A. Yes it does.

HAWAIIAN ELECTRIC CO., INC.
ACCUMULATED DEFERRED INCOME TAXES

	Probable Entitlement *	CIP1 tax depr	Interim
Beginning Balance	132,510	-	132,510
Ending Balance	156,551	(4,518)	152,033
Average Balance	144,531	(2,259)	142,272

* Statement of Probable Entitlement Exhibit 1 page 3.

HECO
CIP CT-1 Deferred Taxes
2009 Test Year

	NOTE A Book Basis	NOTE B Adjustment for AFUDC and TCI	Tax Basis	NOTE A Bonus Depr.	Tax Basis Net of Bonus	2009 MACRS Depreciation	2009 Total CIP CT1 FEDERAL Tax Depreciation	CIP CT1 FEDERAL ADIT EOY
Land	6,119,685		6,119,685					
15 Year Property	149,600,632	2,327,598	147,273,034	2,895,444	144,377,591	7,218,880	10,114,324	3,384,986
20 Year Property	6,679,484	103,924	6,575,560	1,763,187	4,812,373	180,464	1,943,651	675,087
Total (excludes 2010 adds)	162,399,801	2,431,522	159,968,279	4,658,631	149,189,964	7,399,344	12,057,975	4,060,073
							STATE Tax Depreciation	STATE ADIT EOY
Calculation of state tax depreciation								
15 Year Property			147,273,034	-	147,273,034	7,363,652	7,363,652	442,926
20 Year Property			6,575,560	-	6,575,560	246,584	246,584	14,832
			153,848,594	-	153,848,594	7,610,236	7,610,236	457,759
Total End of Year ADIT Balance								4,517,831

NOTE A> see HECO T-16, Attachment 1C (Supplement 5/7/09)

NOTE B>	Estimated AFUDC incurred	11,894,388	see CA-IR-250
	TCI ratio	0.795574	
	TCI incurred	9,462,866	
	AFUDC/TCI difference	2,431,522	

HAWAIIAN ELECTRIC CO., INC.
DEFERRED TAXES ON CIS PROJECT COSTS

	DR / (CR) Rate Case Update	DR / (CR) Revised	DR / (CR) Difference
Deferred Tax at 12/31/08	(854,364)	(857,710)	(3,346)
Deferred Tax at 12/31/09	(2,164,279)	(2,772,748)	(608,469)
Average	(1,509,322)	(1,815,229)	(305,908)

REVISED

	(A) Pre Selection/ Evaluation	(B) Software Implementation	Total	32.8947% Deferred Federal	6.0150% Deferred State	Deferred Total
2003	408,877		408,877	134,499	24,594	159,093
2004	(95,263)		(95,263)	(31,336)	(5,730)	(37,066)
2005	430,341		430,341	141,559	25,885	167,444
2006	148,950		148,950	48,997	8,959	57,956
2007		(1,370,579)	(1,370,579)	(450,848)	(82,440)	(533,288)
2008		(1,726,690)	(1,726,690)	(567,989)	(103,860)	(671,849)
Total	892,905	(3,097,269)	(2,204,364)	(725,118)	(132,592)	(857,710)
2009		(4,921,750)	(4,921,750)	(1,618,995)	(296,043)	(1,915,038)
Total	892,905	(8,019,019)	(7,126,114)	(2,344,113)	(428,635)	(2,772,748)

Note A> Pre Selection / Evaluation costs - outside services: book expense, tax capitalize
Note B> Software Implementation - internal labor and overheads: book defer, tax expense

HECO ST-17
DOCKET NO. 2008-0083

SUPPLEMENTAL TESTIMONY OF
LORIE ANN NAGATA

TREASURER
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: CIP CT-1 Plant Additions in
Statement of Probable Entitlement

INTRODUCTION

Q. Please state your name and business address.

A. My name is Lorie Ann Nagata and my business address is 900 Richards Street, Honolulu, Hawaii 96813.

Q. By whom are you employed and in what capacity?

A. I am employed by Hawaiian Electric Company, Inc. ("HECO" or "Company") as its Treasurer. My educational background and work experience are listed in HECO-1700.

Q. Have you previously testified in these proceedings?

A. Yes, I submitted written direct testimony, exhibits and supporting workpapers as HECO T-17.

Q. What is the nature and scope of your current supplemental testimony?

A. My supplemental testimony supports the Company's response to concerns raised by the Commission in Section III.(c) of its Interim Decision and Order ("Interim D&O"), issued on July 2, 2009 in this docket, related to cost overruns on CIP projects. Specifically, my testimony will identify what plant addition costs are included in the Statement of Probable Entitlement filed on May 18, 2009.

Q. What was the cost estimate for the Campbell Industrial Park Generating Station and Transmission Addition (CIP CT-1) included in Hawaiian Electric's direct testimony?

A. The estimated costs for CIP CT-1 included in Hawaiian Electric's direct testimony was $163,784,251, as shown in HECO-1703.

Q. What was the cost estimate for the CIP CT-1 that was included in Hawaiian Electric's Rate Case Update?

A. The estimated costs for CIP CT-1 included in Hawaiian Electric's Rate Case Update was $164,259,676, as shown in Rate Case Update, HECO T-17, page 6.

Q. Did Hawaiian Electric's update the CIP CT-1 estimates to incorporate the 2008 recorded expenditures and in-service dates and for the impact of 2008 recorded on 2009 estimated expenditures and in-service dates for the various projects for CIP CT-1?

A. Hawaiian Electric considered updating the 2008 year-end rate base balances, including the costs for CIP CT-1, to reflect year-end recorded, and to update 2009 changes to the balances, once the year-end recorded became available. However, Hawaiian Electric was asked by the Consumer Advocate, and the Company agreed, to update these amounts prior to the end of 2008 to provide the Parties with more opportunity to review the updates. (See HECO's response to DOD-IR-94, supplement 3/9/09). The Consumer Advocate disagreed with the Company's interpretation of the request for an early update and conveyed its intention to reflect 2008 year-end recorded balances consistent with prior Company rate cases. In direct testimony, the Consumer Advocate and Department of Defense proposed an adjustment to the average 2009 test year rate base to use 2008 year-end recorded instead of the 2008 estimated balances reflected in the Rate Case Update calculation (see CA-T-3, pages 18-21 and DOD T-1, pages 12-13). The Company did not agree with using 2008 year-end recorded as the 2009 beginning balance in calculating the average rate base without an opportunity to also update its 2009 end of year balance. However, for purposes of reaching a global settlement in the proceeding, the Company agreed to include 2008 year-end recorded balances in the rate base without updating the 2009 end of year balance. (See Exhibit 1, pages 66-67, of the Stipulated Settlement Letter filed on May 15, 2009)

Q. What is the impact to the 2009 plant addition estimate for CIP CT-1 from the use of 2008 year-end recorded as the 2009 beginning balance without the updating the 2009 plant additions to be included in the 2009 end of year balance?

A. The 2009 plant addition estimate for CIP CT-1 and estimated 2009 year-end rate base balance is lower than what it should be. The in-service date for two projects (P0001052 and P0001135) moved from 2008 to 2009. The plant addition costs for those two projects were removed from the beginning balance for settlement purposes, but because the 2009 end of year balance was not updated, the costs for those two projects were not included as 2009 plant additions.

Q. What information does HECO-S-1701 provide?

A. HECO-S-1701 provides an update of HECO-1703 – it presents the CIP CT-1 plant additions and property held for future use as settled between the Parties and used to derive the rate base reflected in Exhibit 1 of the Statement of Probable Entitlement filed on May 18, 2009. HECO-S-1701 shows a total project cost of $163,279,651.

Q. What plant additions amount for CIP CT-1 is included in rate base, as reflected in the Stipulated Settlement Letter and the Statement of Probable Entitlement?

A. As stated above, the amount for CIP CT-1 that was included in rate base was based on the amounts shown in HECO-S-1701. Since the Parties settled on using an average test year rate base, the 2008 plant additions amount is reflected in both the beginning and end of test year balance but the 2009 plant additions amount is reflected only in the end of test year balance. Therefore, only half of the plant additions amount for 2009 is effectively in rate base. Any 2010 amount is not included since it is beyond the 2009 test year. The table below provides the calculation for the average test year rate base amount of $83,769,731 for CIP CT-1, as reflected in the Statement of Probable Entitlement.

	Beginning of Test Year	End of Test Year	Sum
Plant Additions 2008	$6,119,685	$6,119,685	$12,239,370
Plant Additions 2009	0	155,300,091	155,300,091
Sum			$167,539,461
Divided by 2			2
CT-1 Plant Additions in Rate Base			$83,769,731

Q. Does this conclude your testimony?

A. Yes.

Hawaiian Electric Company, Inc.
Campbell Industrial Park Generating Station and Transmission Additions
Plant Additions

Project No.	Description	2008	2009	2010	Total
P0001052	CIP1 CEIP Substation Mod*		3,890		3,890
P0001135	CIP1 Unit Addition-Microwave*				-
P0001340	CIP1 Unit Addition-Easements	4,857,924			4,857,924
P0001585	CIP1 - Land - Gen Station	1,261,761			1,261,761
P0001050	CIP1 AES-CEIP#2 Trans. Line		5,790,887		5,790,887
P0001051	CIP1 AES Substation Add		3,153,110		3,153,110
P0001134	CIP1 Unit Addition-Fiber		531,769		531,769
P0001136	CIP1 Unit Addition-Kahe Bkrs		1,720,778		1,720,778
P0001137	CIP1 Unit Addition-Kalaeloa		289,912		289,912
P4900000	CIP1 Unit 1 Addition		143,809,745	50,000	143,859,745
	Plant Additions	6,119,685	155,300,091	50,000	161,469,776
P0001084	Parcel between Hanua Street and AES Substation (TMK 9-1-26:38) included in Property Held for Future Use				1,809,875
	Total Project Cost				163,279,651

* In Service dates for the projects P0001052 and P0001135 moved beyond 2008. See HECO T-17, Attachment 1, page 1 in the Company's Revised Schedules Resulting from Interim Decision and Order filed July 8, 2009. During Settlement, the Parties agreed to include adjustments resulting from the introduction of 2008 year-end actuals. Thus, plant additions included in the Statement of Probable Entitlement include 2008 recorded plant additions but do not include updates to 2009 plant addition estimates. For CIP1, this results in $456,832 (P0001052) and $523,193 (P0001135) being excluded.

SUPPLEMENTAL TESTIMONY OF
ROBERT C. ISLER

PROJECT MANAGER
POWER SUPPLY ENGINEERING
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Campbell Industrial Park Generating Station and Transmission Addition Projects, Project Costs

INTRODUCTION

Q. Please state your name and business address.

A. My name is Robert C. Isler and my business address is 820 Ward Avenue, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am a Project Manager at Hawaiian Electric Company, Inc. ("Hawaiian Electric", "HECO", or "Company"). My educational background and experience are listed in HECO-S-17A00.

Q. Have you previously submitted testimony in this proceeding?

A. No, I have not.

Q. What is your area of responsibility with respect to this testimony?

A. My testimony will cover the following areas:

1) Cost details of the Campbell Industrial Park Generating Station and Transmission Addition Projects ("CIP CT-1 Projects"), consisting of (1) the construction of a new generating facility (including the acquisition of a nominal 100 megawatt simple-cycle combustion turbine generator and related equipment and auxiliary facilities) ("CT-1"), (2) an approximately two-mile long 138kV transmission line, (3) expansion of HECO's existing Barbers Point Tank Farm site ("Transmission Line Project"), (4) substation upgrades for the AES substation, Campbell Estate Industrial Park ("CEIP") Substation and Kahe Substation ("Substation Upgrades"), and (5) auxiliary equipment and facilities related to the foregoing;
2) Cost management measures taken for the CIP CT-1 Projects;
3) Schedules for the CIP CT-1 Projects; and

4) An overview of the cost estimating process used by the Hawaiian Electric Power Supply Engineering Department.

CIP CT-1 PROJECTS COSTS

Q. What is the current cost estimate for the CIP CT-1 Projects?

A. The current estimate for the CIP CT-1 Projects is approximately $193,100,000. A breakdown of the estimated costs for each separate component project is shown in HECO-S-17A01.

Q. How does this latest cost estimate compare to what was approved in the Decision and Order associated with Docket 05-0146?

A. This latest cost estimate is approximately $55,700,000 higher than the cost estimate of $137,400,000 that was approved in D&O 23457. HECO-T-17A01 shows the breakdown of the estimated costs associated with the D&O 23457 and includes a comparison of that cost estimate with the current cost estimate.

Q. What are the major areas of the project that are responsible for the $55,700,000 difference?

A. Most of the project cost increases above the original estimate are caused by the material costs and construction costs for CT-1 being higher than originally estimated. These two categories account for $53,200,000 of the $55,700,000 difference, or 96% of the increase. Accordingly, the following discussion concentrates on this $53,200,000 difference.

P4900000 – Generating Station Material Costs

Q. Please explain the cost variance for the generating station material costs.

A. The estimated material costs for the generating station project are currently about

$15,000,000 higher than the original cost estimate amount (i.e., approximately $65,000,000 versus approximately $50,000,000).

A detailed breakdown of the material costs for CT-1 and the differences between the original and current cost estimates is presented in HECO-S-17A02.

In general, the cost variances for the materials for the CIP Project can be presented in six categories:

1. Items for which the actual prices were significantly less than estimated.
2. Items for which the actual prices were very close to the original estimate.
3. Items for which the scope did not change, but the actual prices were significantly higher than estimated.
4. Items for which the scope did change and the actual unit prices were significantly higher than estimated.
5. Items which were not included in the original estimate.
6. Items which were included in the original estimate, but deleted from the final scope.

Within these categories, I have also explained changes in specific major items as appropriate.

<u>Category 1 Materials</u> - Items for which the actual prices were significantly less than estimated.

Q. Please explain the cost variances for the materials identified as Category 1 in HECO-S-17A02.

A. The materials listed in HECO-S-17A02 as Category 1 items are those for which the actual prices were significantly less than estimated. This category consists of the water treatment system and the blackstart generators. The total cost for these items is currently $1,166,000 lower than the original estimate of $8,562,000 for these items.

For the water treatment system, the primary reason for the lower cost was that Hawaiian Electric was able to get a tax exemption since this equipment is categorized as a pollution control device.[1] This tax exemption resulted in a cost savings of $221,000 for the water treatment system purchase.

For the blackstart generators, as part of the combustion turbine bids, Siemens was asked to provide a bid to supply the blackstart generators for their unit. Siemens offered a unit from a subvendor for a total of $3,710,000. Hawaiian Electric included this price in its original cost estimate. To support cost management for this project, HECO decided to competitively bid the blackstart generator equipment to multiple suppliers. The end result was that Hawaiian Electric was able to obtain the blackstart generators for $2,766,000, which is $944,000 less than the original bid from Siemens.

<u>Category 2 Materials</u> - Items for which the actual prices were very close to the original estimate.

Q. Please explain the cost variances for the materials identified as Category 2 in HECO-S-17A02.

A. The items listed in HECO-S-17A02 as Category 2 items are those for which the actual prices were very close to the original estimate. The cost for these two items (shop tanks and generator circuit breaker) is currently $51,000 lower than the original estimate of $632,000.

[1] The water treatment system purifies water that will be injected into the combustion turbine to control the emissions of NOx.

Category 3 Materials - Items for which the scope did not change, but the actual prices were significantly higher than estimated.

Q. Please explain the cost variances for the materials identified as Category 3 in HECO-S-17A02.

A. The items listed in HECO-S-17A02 as Category 3 items are those for which the scope did not change, but the actual prices were higher than estimated. All of these items were competitively bid to multiple vendors to obtain the best price. In general, the items in these categories are made of materials (copper, steel, stainless steel) that increased in cost significantly between the time that the original estimate was developed and final purchases were made. As discussed in greater detail by Mr. Lunardini in HECO-ST-17B at pages 5 through 10, there were a number of unusual market conditions that resulted in material and construction labor cost escalations beyond the normally expected annual price escalation. For example, transformer and large electrical equipment cost indices rose by 49% between April 2005 and December 2008.

The total cost for these items was $9,976,000 higher than the original estimate of $36,439,000 - an increase of 27%. The increase in the cost of the combustion turbine ($6,771,000) and transformers ($1,825,000) account for over half of the increase in this category.

Combustion Turbine

Q. Please explain the cost variance for the combustion turbine.

A. The total increase in the cost of the combustion turbine from the original estimate to the final estimate is approximately $6.77 million. This total increase is made up of the following components:

- Escalation per Contract: +$3.83 million
- Higher Shipping Costs: +$1.33 million
- Biodiesel Testing +$0.65 million
- Taxes +$0.36 million
- Fuel purging system for biodiesel +$0.33 million
- Storage +$0.27 million

Q. Please explain the increase in escalation for the combustion turbine.

A. As stated in Hawaiian Electric's direct testimony HECO T-9 of Docket 05-0145, page 30 (filed April 18, 2006), the combustion turbine generator package pricing from Siemens was set up with a portion that was fixed and a portion subject to escalation.[2] The escalation formula for the portion of the generator package subject to escalation uses established, published indices. Based on giving Siemens full notice to proceed on August 13, 2007, the escalation formula in the contract resulted in an increase of $3.83 million above the original contract amount. Since the price adjustment due to escalation could not be accurately estimated (i.e., the amount or direction of changes in the published indices could not be accurately estimated), the original contract amount was used to represent the cost estimate for the generator package in the original project cost estimate included in the application submitted to the Commission. The entire escalated amount represents an increase in the estimated cost of the generator package.

The following table shows the original and final multiplication factors for each of the various indices used in establishing the final combustion turbine

2 Additionally, Siemens is to be reimbursed for actual transportation costs plus 8%.

generator package price. The multiplication factor was applied only to the variable portion of the Contract Price.

Original and Final Multiplication Factors		
Index	**Original –December 2005**	**Final – August 2007**
US Employment Cost Index for Private Industry	0.50	0.53
Average Hourly Wage – Ontario Canada	0.05	0.05
North American Carbon Steel	0.22	0.23
Stainless Steel	0.17	0.33
Copper	0.01	0.02
Consumer Price Index	0.05	0.05
Total	**1.00**	**1.20**

Fixed Portion of CT Price: **$9,500,000**

Variable Portion of CT Price: **$19,137,787**

Original Contract Price = $9,500,000 + ($19,137,787 x 1.00) = **$28,637,787**

Final Price at Notice to Proceed = $9,500,000 + ($19,137,787 x 1.20) = **$32,471,086**

Price Escalation = $32,471,086 - $28,637,787 = **$3,833,299**

Q. Please explain the increase in shipping costs for the combustion turbine.

A. Hawaiian Electric was not planning to give Siemens a notice to proceed with manufacture of the combustion unit until all major discretionary approvals (i.e., regulatory and air permit approvals) were received. Because it was anticipated that these approvals would not be obtained for at least 18 months following the signing of the combustion turbine contract, Siemens would not provide a firm cost for shipping of the equipment due to the volatility of fuel pricing and its affect on shipping costs.[3] Therefore, Hawaiian Electric agreed that it would reimburse Siemens for the shipping at actual cost plus 8%. For the original estimate, it was estimated that the total cost of shipping the combustion turbine-generator package to the site would be $3,588,000. However, the final cost of shipping was $4,916,000, which was $1,328,000 higher than originally estimated. Hawaiian Electric worked with Siemens to obtain the most cost-effective transportation of the equipment and believe the best reasonable price was obtained.[4] The original estimate for the total transportation cost was low primarily due to two reasons (1) oil prices had increased significantly between the time of the original estimate and when shipping was done, and (2) Siemens underestimated the technical requirements and the additional costs to comply with Jones Act requirements[5].

Q. Please explain the cost variance associated with biodiesel testing.

A. Although the combustion turbine vendor (Siemens) committed to designing the combustion turbine to use biodiesel based on known fuel specifications and anticipated combustor dynamics, both HECO and Siemens believed it was prudent to conduct laboratory testing with biodiesel. This testing was done using the same model of combustion parts used on the engine delivered to HECO and was done to accomplish the following:

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[3] Subsequently, Hawaiian Electric discovered that it was becoming more common for vendors to not provide firm pricing for shipping. The water treatment equipment for this project is another example of where a cost plus arrangement for shipping was required by the vendor.

[4] The Siemens project team also had an incentive to minimize the transportation cost since their team acts as a separate cost center within their company. The original quotes from the shipping companies totaled as much as $6,000,000; but Siemens, with Hawaiian Electric's assistance, was able to lower this cost by over $1,000,000.

[5] The Jones Act requires that maritime shipments within the United States be done using United States flagships constructed in the United States. The number of vessels meeting this Jones Act requirement and capable of shipping the Siemens equipment is very limited. Also, the cost for using these ships is much higher than what Siemens usually encounters for international shipments. Siemens usually transports their equipment within the United States by truck and rail.

- Analyze the specific combustor dynamics and metal temperatures using biodiesel and make adjustments to the equipment, as necessary. This was best done in a laboratory environment where all the necessary parameters could be measured properly.
- Analyze air emissions and making adjustments, as necessary, to the combustion equipment to optimize emissions when firing biodiesel.

The cost to HECO for this testing was $650,000. This cost includes the laboratory costs and fuel costs incurred during the laboratory testing. Siemens covered the cost of the combustion equipment used in the testing.

Q. Please explain the cost variance associated with taxes.

A. The additional $360,000 in taxes is due to two factors. First, since the total price for the turbine is higher, the total amount for taxes increased. Second, the original estimate included a tax rate of 4.5%, while the actual tax rate used in the contract was 4.712%. With the imminent excise tax rate increasing to 4.5%, the original Hawaii excise tax rate should have been based on the effective tax rate of 4.712% to account for the gross up of the excise tax rate effect, instead of the nominal rate of 4.5%

Q. Please explain the cost variance associated with the fuel purging system.

A. The additional $361,000 increase in combustion turbine cost is primarily due to the addition of a fuel purging system and fuel nozzle modifications to address a potential coking problem[6] when firing biodiesel in CT-1. During the laboratory

[6] Coking is the formation of carbonaceous deposits on metal parts (fuel nozzles in this case) at high temperatures. These deposits will affect the fuel spray pattern which can lead to significantly reduced efficiency and possibly prevention of unit operation. Coking occurs with biodiesel during shutdown when there is residual fuel left in the fuel nozzles and no cooling. Siemens is modifying the design to purge the

testing with biodiesel that Siemens completed in the fourth quarter of 2008, some coking of the fuel nozzles was observed. Coking was not observed when firing regular #2 diesel fuel in the test rig, which is consistent with Siemens field experience with #2 diesel.

Q. Please explain the cost variance associated with storage.

A. Typically, fabrication of the equipment associated with the purchased combustion turbine-generator equipment does not occur until an order is placed. However, at the time Hawaiian Electric issued a bid for the combustion turbine unit, Siemens had available in storage the two major components (the turbine and the generator).[7] Hawaiian Electric chose to purchase these existing components, thereby saving approximately $1,500,000. As part of the contract, Siemens agreed to cover the storage costs for about one year, after which Hawaiian Electric was responsible for the storage costs at $29,000 per month. At the time of contract negotiation, it was uncertain when release for manufacturing (thereby ending the storage cost period) would be given to Siemens since this date was tied to receiving regulatory and air permit approvals. As it turned out, Hawaiian Electric was responsible for covering approximately nine months of storage costs. This effectively reduced the savings of buying a pre-manufactured turbine and generator to a total of $1,230,000.

<u>Transformers</u>

Q. Please explain the cost variance for the transformers.

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fuel out of the fuel nozzles at shutdown to minimize possibility of coking. They are also changing the fuel nozzles so that the tips can be removed for cleaning in the event some coking does occur.

[7] Siemens had previously manufactured the turbine and generator as part of an order placed by Enron, who later cancelled the order. These pieces of equipment were stored in environmentally controlled warehouses and never operated prior to delivery to Hawaiian Electric.

A. The estimated costs for the transformers needed for this project are approximately $1,800,000 higher than originally estimated. Most of the cost increase is due to transformer market prices increasing significantly since the time the original project cost estimate was completed. However, part of the cost increase is due to two additional transformers that were identified as necessary for station reliability and to supply station loads.

The original cost estimate assumed two new transformers would be installed, a 160MVA generator step-up transformer and a 15MVA auxiliary transformer. As the plant design matured, the need for a 5MVA backup transformer was identified.[8] Also, as the electrical design was finalized, it was determined that an additional station transformer (4160V/480V) to serve the control/administration building loads was needed since the transformer originally ordered with the switchgear was not large enough. The table below shows the original cost estimates and actual costs for these transformers:

	Original Cost Estimate	**Current Actual/Estimated Costs**
Generator Step-Up Transformer	$1,131,694	$2,205,382
Auxiliary Transformer	241,428	463,500
Backup Transformer	0	265,981
Station Service Transformer	0	115,388
Totals	**$1,373,122**	**$3,198,042**

Q. What steps were taken to insure the best prices for these transformers?

[8] The backup transformer is necessary to provide power to the station in the case the auxiliary transformer fails.

A. To help ensure that HECO obtained the best pricing for the large generator step-up ("GSU") transformer, HECO issued a request for proposal for this equipment and received competitive bids from six qualified vendors ranging from $2,200,000 to $3,300,000. Based on the fact that ABB was the low bidder on the GSU transformer and that HECO has an alliance agreement with ABB that would apply to the smaller transformers, the auxiliary and backup transformers are being sole-sourced to ABB.

A price increase of almost 100% over a two-year period is unprecedented, and therefore would have been almost impossible to anticipate. However, this level of price increase is consistent with what HECO experienced with other competitively procured transformers over that period of time. Also, Sargent & Lundy observed comparable transformer price increases over the same period with their other clients. The transformer market as a whole experienced significant price increases and HECO took prudent steps to obtain competitive prices for these transformers.

The remainder of the items in this category increased by a total of $1,380,000, or 184%. The increases were due primarily to increases in material costs as described for CT-1 and the transformers. Each of these items was competitively bid to obtain the best pricing at the time.

<u>Category 4 Materials</u> - Items for which the scope did change and the actual unit prices were significantly higher than estimated.

Q. Please explain the cost variances for the materials identified as Category 4 in

HECO-S-17A02.

A. The items in Category 4 materials are those materials for which the scope did change and the actual unit prices were significantly higher than estimated. In general, the changes in scope involve an increase in the actual size or quantities of items in the final design compared to the original estimate. The current total estimated cost for the Category 4 materials is $9,254,000, which is $5,312,000 more than the original estimate of $3,831,000. This represents an increase of 139%. Other than the spare parts, approximately half of this increase can be attributed to higher than estimated unit prices, and the other half is due to increases in scope. The table below provides a brief summary of the scope changes.

Item	Scope Change from Original Estimate to Final Design
Spare Parts	see discussion below
Valves & Specialties	Increased from 156 ea. to 184 ea. Switched many valves from manual to motor-operated or air-operated to facilitate remote plant operation.
Switchgear & MCCs	Increased number and sizes of switchgear connections as details of the water treatment and blackstart capability were finalized.
Air Compressors	Size of instrument air compressors and receivers increased. The original estimate assumed the CT air intake filters would not be cleanable with compressed air and therefore did not take into account the large air demand for periodically cleaning the filters.
Large Bore Piping	Increased total length from 14,420 ft. to 16,944 ft. Also changed mix of pipe to include higher percentage of 8" diameter and larger pipe.
Field Instruments	Increased number of instruments from approximately 60 ea. to 115 ea. Also added 6 specialty instruments totaling ~$140,000 for heat rate monitoring and environmental compliance.

Supply & Injection Wells	Added two stormwater injection wells. Original estimate assumed runoff would be directed to the City stormwater system, which proved to not be practical.
Pumps	Eliminated the need for an electrical powered fire pump and two wastewater transfer pumps. Added two fuel unloading pumps. The original estimate assumed fuel would be delivered by pipeline.

Spare Parts

Q. Please explain the spare parts cost variance.

A. The original estimate included $968,000 for spare parts, primarily for the Siemens combustion turbine. Recently, Hawaiian Electric joined an independent, owner-sponsored users' group for this combustion turbine and attended a "mid-year" meeting in January 2009. Based on discussions with other equipment owner's, Hawaiian Electric was made aware that the lead times for many spare parts have significantly increased. Also, Siemens' inventory of readily available spare parts is not as expansive as originally thought. Therefore, Hawaiian Electric may need to keep more spare parts than originally anticipated and the current estimate includes an additional $1,732,000 for spare part allowance. Hawaiian Electric will be working closely with other owners experience with this particular CT as well as Siemens to optimize the list of spare parts that need to be kept in Hawaiian Electric inventory.

Category 5 Materials - Items which were not included in the original estimate.

Q. Please explain the cost variances for the materials identified as Category 5 in HECO-S-17A02.

A. Category 5 items are those which were not included in the original estimate. Some of these items such as the shop equipment, furniture, security equipment, and communication equipment are still being procured. The amounts listed in the table are allowances for these items, which are subject to change. Hawaiian Electric will take measures to ensure that it receives the best reasonable cost for these items. The entire $1,188,000 cost for Category 5 items is in addition to the original estimate.

Category 6 Materials - Items which were included in the original estimate, but deleted from the final scope.

Q. Please explain the cost variances for the materials identified as Category 6 in HECO-S-17A02.

A. Category 6 items are those which were included in the original estimate, but ultimately not needed in the final design. The entire $648,000 cost for Category 6 items represents a savings compared to the original estimate.

P4900000 – Generating Station Construction Costs

Q. What is the current estimate for the generating station construction costs?

A. The current estimate for the generating station construction cost is $80,100,000 compared to the D&O estimate of $41,600,000. This is an increase of $38,500,000 over the original estimate.

Q. What construction costs as currently estimated are different than the original cost estimate and why?

A. A breakdown of the construction cost differences is shown in HECO-S-17A01.

Explanations of why the current costs differ from those originally estimated are provided in the following testimony.

Hawaiian Dredging Construction Company, Inc. ("HDCC") - Civil/Structural Substructure Installation, Foundations & Ductruns

Q. Please explain the cost variance for the substructure installation, foundations, and ductruns.

A. For the underground electrical duct banks and equipment foundations there was an approximately $4,450,000 cost variance. Of the $4,450,000 difference between the current and original cost estimates for the civil/structural work, $2,910,000 is due to electrical ductbanks and $1,540,000 is due to equipment foundations.

The final design for the underground electrical ductbanks required more excavation/concrete backfill and included significantly more conduits than what was originally assumed. These differences between the original assumptions and the final design resulted in the higher cost. The following table shows a comparison of assumptions made for the original cost estimate versus final design parameters:

Comparison of Original Assumptions and Final Design
For Underground Electrical Duct Banks

	Original Assumptions	**Final Design**
Low voltage ductbank concrete	240 cu. yd.	1,542 cu. yd
Number of low voltage ductbank manholes	4 ea.	9 ea.
Total length of conduit in low voltage ductbanks	12,000 ft.	87,935 ft.
High voltage ductbank concrete	730 cu. yd.	901 cu. yd.
Number of 138kV ductbank manholes	4 ea.	0 ea.
Total length of conduit in 138kV ductbanks	9,150 ft.	~13,200 ft.

The primary difference (number and length of conduits) resulted because the final design required many more electrical connections than what was originally assumed. The conceptual design assumptions did not take into account the final level of automation and reliability/redundancy that would be required for remote start/stop operational requirements, which had not been defined at that time.

Overall, final equipment foundation designs ended up being larger than what was assumed for the original cost estimate. The following table shows differences in the total amount of concrete needed for the major equipment foundations:

Comparison of Original Assumptions and Final Design
Requirements for Cubic Yards of Concrete in Foundations

	Original Assumptions	**Final Design**	**Difference**
Exhaust Stack	250 cy	828 cy	578 cy (231%)
Water Treatment Bldg.	417 cy	947 cy	530 cy (127%)
Fuel Tanks	500 cy	1,106 cy	606 cy (121%)
Demin Water/Startup Tank/BOP Equipment	300 cy	1,960 cy	1,660 cy (553%)
CT & Accessories	660 cy	1,111 cy	451 cy (68%)
GSU & Aux Transformers	75 cy	342 cy	267 cy (356%)
Service Water Tanks	190 cy	205 cy	15 cy (8%)
Diesel Generators	125 cy	66 cy	-59 cy (-47%)

There are various reasons why most of the foundations ended up being larger than originally assumed. For many of the foundations (exhaust stack, fuel tanks, combustion turbine and accessories), assumptions had to be made for loads and soil conditions. These assumptions were ultimately not conservative enough. Following purchase of equipment and subsequent receipt of final equipment design and loads, final foundations designs were completed. As shown in the table above, the final foundation designs required substantial increases in the required amount of concrete.

Steel and Gallery Installation

Q. Please explain the cost variance for the steel and gallery installation.

A. The original cost estimate included an allowance of $131,000 for steel platforms and galleries. The current cost estimate does not have any money allocated to this category. However, it is expected that there will be some access platforms and galleries needed for the project. These are currently allotted for in the change order line item since details are not complete at this time.

Civil Work

Q. Please explain the cost variance for the civil work.

A. For the civil work, the cost is currently $3,120,000 higher than the original estimate of $3,590,000. Approximately half of this increase is due to changes in scope involving the storm drain system, sanitary waste systems, landscaping, and tank containment berm work. The other half of the increase appears to be due to underestimating the premium in Hawaii for this type of work.

The original estimate did not include the stormwater detention pond that was ultimately required by City & County of Honolulu rules. At the conceptual design phase of this project, the details of how stormwater runoff would be handled were very preliminary because it was not clear what would be feasible or allowed at the time. After many months of design iterations between Hawaiian Electric, Sargent & Lundy, and the City & County of Honolulu, the design concept for stormwater runoff was finalized.

Since there is no sanitary system for all of Campbell Industrial Park, the generating station requires its own stand alone system. The original concept for the generating station sanitary waste system was to have a septic tank for which all contents would be pumped out on a periodic basis. However, it was later determined that this type of arrangement is not allowed by Department of Health rules. The liquid waste must be treated and disposed. Therefore, a sanitary piping system with approximately 1,200 feet of underground piping, manholes, cleanouts, and lift stations were added to the scope.[9]

The original design estimate did not include an allowance for landscaping because it was not thought to be required since there is no specific rule for this in the Land Use Ordinance. However, to obtain permits from the City & County of Honolulu, the design was required to include landscaping of the parking lot areas.

This project involved significant modifications to the existing fuel tank containment area. The original cost estimate incorrectly assumed that all of the tank berm walls could be built up using soil that was excavated from other areas of the site. As it turned out, the existing soil could not meet the compaction requirements for the berm, so new soil had to be imported to the site to complete the berm work.

<u>Painting</u>

Q. Please explain the cost variance for painting.

[9] The concept of using a less expensive leech field was also explored, but eventually ruled out due to space limitations.

A. The current cost estimate for painting is $830,000, or $732,000 higher than the original cost estimate of $98,000. The original estimate assumed the only painting needed (other than tanks, for which the cost is included in the tank estimate) would be for touch-up painting. However, several other items required painting in the field, including the exhaust stack, combustion turbine air inlet, and piping. Therefore, the final paint cost was significantly higher than originally estimated.

To ensure that painting was done at the best possible cost at the time, Hawaiian Dredging competitively bid the painting work to several local industrial painting companies. The lowest bid was received from Zelinksy Painting. Hawaiian Dredging shared the bids with Hawaiian Electric as part of the open-book process and passed on the Zelinsky price (with 12% markup) to Hawaiian Electric.

<u>Demolition</u>

Q. Please explain the cost variance for demolition.

A. The actual cost for demolition is $130,000, or $4,000 less than the original cost estimate of $126,000. Since there was only one small structure and some minor underground ducts that required demolition, the scope of this work was well defined (even in the conceptual phase), so the cost estimate was relatively close to actual costs.

<u>HDCC - Electrical</u>

<u>Electrical Major Equipment Installation</u>

Q. Please explain the cost variance for electrical major equipment installation.

A. The current cost estimate for installation of major electrical equipment is $1,060,00, or $220,000 more than the original cost estimate of $840,000. This category includes the installation of electrical equipment such as the main and auxiliary transformers, isophase bus duct, non-segmented bus duct, switchgear, and motor control centers. For the most part, these pieces of equipment were well defined at the conceptual design phase, but some of the equipment (e.g., switchgear) was more involved.

Electrical Balance of Plant Installation

Q. Please explain the cost variance for electrical balance of plant installation.

A. The current cost estimate for installation of the electrical balance of plant equipment is $5,540,000, or $2,340,000 more than the original cost estimate of $3,200,000. This category includes installation and termination of cables, installation of aboveground conduits, cable trays, small electrical panels and transformers, lighting, security surveillance system, and miscellaneous devices. The primary reason for the higher cost in this area is due to the significant increase in the amount of wiring and terminations required in the final design compared to the assumptions used in the original cost estimate. The following table shows a comparison of assumptions made for the original cost estimate versus final design parameters:

Comparison of Original Assumptions and Final Design
For BOP Electrical Cables

Cable Type	Original Assumptions	Final Design
Medium Voltage Power	3,500 ft.	11,183 ft.
Low Voltage Power	25,000 ft.	129,951 ft.
Control	70,000 ft.	116,371 ft.
Instrument & Thermocouple	85,000 ft.	133,031 ft.
Total	**183,500 ft.**	**390,536 ft.**

<u>High Voltage (138kV) Lines to Substation</u>

Q. Please explain the cost variance for high voltage lines to the substation.

A. The current cost estimate for installation of the high voltage lines to the substation is $145,000, or $16,000 more than the original cost estimate of $129,000. This scope was well defined in the conceptual design phase. Therefore, final costs were relatively close to estimated cost. Additionally, in an attempt to get a better price, Hawaiian Electric explored the possibility of the cable manufacture (Prysmian) installing this cable instead of Hawaiian Dredging's electrical subcontractor (American Electric). Hawaiian Electric received a bid from Prysmian to install this cable for $489,000, which was approximately $336,000 more than the HDCC/American Electric bid. Therefore, Hawaiian Electric chose to have American Electric install the cable. Also, to ensure that American Electric was current in the latest installation techniques for the exact type of terminators supplied by Prysmian, Hawaiian Electric paid to have Prysmian provide training to the American Electric crews. This training accounts for the bulk of the cost difference.

<u>HDCC – Furnish & Erect</u>

<u>Field Erected Tanks</u>

Q. Please explain the cost variance for the field erected tanks.

A. The current cost estimate for installation of the field erected tanks is $5,850,000, or $2,220,000 more than the original cost estimate of $3,630,000. The tanks included in this category are the two bulk fuel storage tanks, the startup fuel tank, the two demineralized water storage tanks, and the two service water storage tanks. The scope of work assumed for the tank work in the original estimate and the final design for the tank work did not change much. The only significant change was that the original estimate assumed there would only be one service water tank, but larger in size than the two in the final design. The main reason for the higher cost is due to market conditions and commodity prices for steel at the time. The contract for these tanks was signed at time when steel was near or at its peak price.

To ensure the best pricing was received for the construction of these tanks, Hawaiian Dredging competitively bid the tank construction to several experienced companies that specialize in this type of work. Based on the competitive bids, Hawaiian Dredging awarded the tank installation work to Chicago Bridge & Iron ("CBI"). CBI provided the lowest price and the best schedule to complete the work. Hawaiian Dredging shared the bids with Hawaiian Electric as part of the open-book process and passed on the CBI price (with 10% markup) to Hawaiian Electric. As discussed earlier, the painting was also competitively bid and Zelinsky was the lowest bidder for the paining work.

Fire Protection

Q. Please explain the cost variance for the fire protection.

A. The current cost estimate for supply and installation of the fire protection systems is $368,000, or $295,000 less than the original cost estimate of $663,000. The original cost estimate assumed that naphtha would be the primary fuel for the combustion turbine. Therefore, a foam deluge system was included in the price estimate. However, the foam deluge system is not required for diesel or biodiesel so it was deleted from the project scope of work. Deletion of this part of the fire protection system from the scope of work accounts for the cost difference.

Buildings

Q. Please explain the cost variance for the buildings.

A. The current cost estimate for building construction is $10,480,000 or $6,140,000 million more than the original cost estimate of $4,340,000. The sizes of both the control building[10] and water treatment building increased from the conceptual design that was assumed for the original cost estimates. The control building was originally envisioned to be a two-story building. However, as the design and site layout for the entire plant continued to evolve, it became evident that the footprint of this building needed to be reduced to avoid conflict with the nearby overhead transmission lines and Chevron's underground pipelines. With this reduction in footprint size, the only alternative to provide the identified space needed was to add a third story to the building, which increased the total square footage by about 38%.

The conceptual design for the water treatment building used for the original cost estimate assumed a building footprint of 75' x 75'. However, following detailed reviews with water treatment vendors, it was determined that the water treatment building footprint needed to be increased by 25 feet in both directions to accommodate all of the equipment that it will house. Therefore, the overall footprint increased by approximately 78% from the original estimate.

[10] Although this building is referred to as a control building for convenience, it provides a location for multiple purposes. In addition to the plant controls and control room, this building will also consist of a maintenance shop, instrument shop, personnel offices, a conference room, a library, IT equipment and shower/locker room facilities.

At the time the building work was bid out for construction, the building construction market in Hawaii was very strong and pricing had been steadily increasing and hard to predict. One of the reasons that Hawaiian Dredging was chosen as the general construction contractor for this project was because their building costs were approximately $4,500,000 less than the other general contractor bidder.

HDCC – I&C

Instrument & Controls

Q. Please explain the cost variance for instrument and controls.

A. The current cost estimate for installation of instrument & control systems is $395,000, or $153,000 more than the original cost estimate of $242,000. The final design includes more instruments than originally assumed. The conceptual design assumptions did not take into account the final level of automation for remote start/stop operational requirements, which had not been defined at that time.

HDCC - Mechanical

Combustion Turbine Erection

Q. Please explain the cost variance for combustion turbine erection.

A. The current cost estimate for combustion turbine erection is $5,430,000, or $3,210,000 more than the original cost estimate of $2,220,000.

The original cost estimate underestimated the man-hours it would actually take to construct the combustion turbine-generator. Part of this underestimation was because the original cost estimate did not take into account that the large air inlet system for this project had to be situated on top of the generator instead of beside it. This change added close to 10,000 man-hours to the construction. Also, the original estimate was likely too optimistic about how many man-hours it should take to construct this equipment, even without the more complicated air inlet. Subsequent inquiries were made to Siemens about the number of man-hours they would estimate for CT erection. The Siemens estimate had approximately 10,000 more man-hours than the 16,000 man-hours included in the original estimate.

Fuel Conditioning Equipment Installation

Q. Please explain the cost variance for fuel conditioning installation.

A. The current cost estimate for fuel condition installation is $0, or $91,000 less than the original cost estimate of $91,000. When the original cost estimate was developed, it was not certain what fuel the combustion turbine would use or where it would come from. Even after the decision was made that the unit would run on diesel until which time it is switched to biodiesel, it was not certain if any fuel conditioning would be needed or even feasible. After learning more about biodiesel, it appeared that fuel conditioning would not be needed. However, since the biodiesel may now be barged/shipped from the US West Coast, some type of fuel conditioning may be needed in case the biodiesel picks up contamination in transit. If additional equipment is eventually needed, the total cost is estimated to be less than $91,000.

Bulk CO2 Gas Storage Installation

Q. Please explain the cost variance for bulk CO2 gas storage installation.

A. The current cost estimate for bulk CO2 gas storage installation is $0, or $28,000 less than the original cost estimate of $28,000. The original estimate assumed that separate CO2 storage would be needed for combustion turbine fire protection.

However, the combustion turbine was supplied with its own CO2 storage system, so this work was deleted from the project scope of work.

Balance of Plant ("BOP") Equipment Installation

Q. Please explain the cost variance for BOP equipment installation.

A. The current cost estimate for BOP equipment installation is $234,000, or $65,000 less than the original cost estimate of $299,000. This category includes mechanical installation of various pumps, air compressors, shop fabricated tanks, blackstart generators and a guard shack. The scope of this work did not change much from conceptual to final design. The original cost estimate assumed more labor hours than required to install this equipment. Therefore, the actual cost is less than estimated.

BOP Piping, Valves & Specialties Installation

Q. Please explain the cost variance for BOP piping, valves and specialties installation.

A. The current cost estimate for BOP piping, valves & specialties installation is $5,470,000, or $1,260,000 more than the original cost estimate of $4,210,000. The following table shows a comparison of assumptions made for the original cost estimate versus final design parameters:

Comparison of Original Assumptions and Final Design
For Piping & Valves

	Original Assumptions	**Final Design**
Large Bore Pipe – 2.5" dia.	300 ft.	48 ft.
Large Bore Pipe – 3" dia.	1,000 ft.	1,877 ft.
Large Bore Pipe – 4" dia.	2,270 ft.	2,588 ft.
Large Bore Pipe – 6" dia.	7,500 ft.	4,303 ft.
Large Bore Pipe – 8" dia.	1,750 ft.	3,822 ft.

Large Bore Pipe – 10” dia.	0 ft.	1,147 ft.
Large Bore Pipe – 12” dia.	1,600 ft.	3,159 ft.
Total Pipe Length	**14,420 ft.**	**16,944 ft.**
Valves	156 ea.	184 ea.

The total amount of large bore (>2.5” diameter) piping increased by about 17%, but much of the pipe ended up being larger diameter than originally estimated, which accounts for the higher percentage of cost increase. Similarly, the amount of valves increased by about 18%, but many of them were upgraded to motor operated control valves, which also increases the installation cost.

Exhaust Stack Construction

Q. Please explain the cost variance for exhaust stack construction.

A. The current cost estimate for exhaust stack construction is $1,620,000, or $1,230,000 more than the original cost estimate of $390,000.

At the time the original cost estimate was created, it was underestimated how large the foundation for a 210 feet tall stack capable of withstanding hurricane force winds would have to be. Therefore, the original assumptions also underestimated how much it would cost to construct the stack.

After receiving the final stack design from Siemens, Hawaiian Dredging provided the drawings to CBI since they planned to subcontract this work to them (based on their low bid on tank construction). CBI quoted a price that would have resulted in stack construction costs of about $2,040,000. Hawaiian Dredging evaluated what it would cost for them to self-perform the stack construction and determined they could do it for a total of $1,620,000. This savings of $420,000 was passed along to Hawaiian Electric.

Cranes & Hoists

Q. Please explain the cost variance for cranes and hoists.

A. The current cost estimate for cranes & hoists is $0, or $6,000 less than the original cost estimate of $6,000. The original estimate had an allowance for a small hoist that was subsequently deemed not necessary.

Water Treatment Installation

Q. Please explain the cost variance for water treatment installation.

A. The current cost estimate for mechanical installation of the water treatment system is $1,110,000, or $620,000 more than the original cost estimate of $490,000.

The original estimate for the water treatment system assumed that it would be a two-train system requiring a feed of approximately 800 gpm. This assumption holds true for use of groundwater as the feedwater. However, during the design process, Hawaiian Electric chose to have the system designed so that it can also treat reclaimed water from the Honouliuli wastewater treatment facility and potable water. This decision was made so that the water treatment system has significant redundancy and flexibility to maximize the reliability of the generating station. As evidenced by the larger footprint of the water treatment building, this capability added more skids and piping to the system, which resulted in a higher mechanical installation cost.

HDCC - Off-Site Storage/Trailers

Q. Please explain the cost variance for off-site storage/trailers

A. The current cost estimate for off-site storage/trailers is $470,000, or $470,000 more than the original cost estimate of $0.

Although the new generating station site is relatively small and tight for construction, it was originally thought that the equipment could be stored on site during construction. However, once it was better understood how the materials would be delivered to the site and the schedule for delivery, it became clear that offsite storage needed to be leased to accommodate the large number of truckloads of materials and the total volume of materials. Primarily, the offsite storage was to handle the approximately 150 truckloads of ancillary materials associated with the Siemens combustion turbine. The turbine, generator, and stack pieces from Siemens were all shipped directly to the construction site and were not stored at the off-site storage location.

In addition to the one office trailer that Hawaiian Electric purchased as part of the construction project, several other office trailers were necessary to provide temporary office space for vendor technical field assistance personnel and Hawaiian Electric personnel until the control/administration building is completed. Hawaiian Dredging had additional trailers that were available for Hawaiian Electric to lease at a much lower rate than from outside vendors.

HDCC - Indirects

Q. Please explain the cost variance for indirects.

A. The current cost estimate for indirects is $11,810,000, or $4,170,000 more than the original cost estimate of $7,640,000.

Indirects are essentially overhead costs for the construction contractor to cover costs for their on-site field supervision staff, trailers, trucks, consumables, small tools, utility charges, surveying, bonds, insurance, etc. The contractors indirect costs can also be a measure of the market conditions and can vary between projects of the same scope constructed at different times. The methodology used to estimate these indirects in the original cost estimate are covered by Mr. Lunardini in HECO ST-17B.

One of the reasons that Hawaiian Dredging was chosen as the general construction contractor for this project was because their indirect costs were less than the other general contractor bidder. For approximately the same number of labor hours estimated to complete the scope of work as it was defined at that time, the other bidder's indirect costs and fees were approximately $5,000,000 higher than those of Hawaiian Dredging.

<u>HDCC - Change Orders</u>

Q. Please explain the cost variance for change orders.

A. Because there is currently a generating capacity shortfall on Oahu, measures were taken to install this new increment of generating capacity as soon as practical. To accomplish this, increments of the construction contracts were signed based on "90% design" drawings instead of a complete set of "for construction" drawings. Once the final construction drawing packages were completed, they did include differences from the "90% design" drawing package. These differences will be covered by change orders to the construction contract.

Additionally, there are always situations that arise and conditions found during a large project such as this that cannot be fully anticipated. Sometimes these items will result in additional construction costs. An example of this type of situation with the CIP CT-1 Projects is the costs associated with handling and disposing of oil-contaminated soil and water at the site. The presence of this oil layer under the control building also required installation of a vapor protection/detection system that was not included in the original cost estimate.

Based on the items that have been so far identified as changes, it is estimated that the total additional cost will be about $5,150,000.

Pacific Commercial Services/Philip Services/Haztech

Q. Please explain the cost variance for services provided by Pacific Commercial Services, Philip Services, and Haztech.

A. The current cost estimate for services from these companies is $126,000, or $126,000 more than the original cost estimate of $0.

These companies were directly contracted to assist in remediating subsurface contamination encountered during excavation at the site. Hawaiian Dredging also incurred costs to handle and dispose of oily waste, but those costs are covered under the change order allowance for Hawaiian Dredging discussed above.

Until the final design was completed, it was unknown what parts of the project would encounter the water table (about 10 feet below the surface) at the site. Also, the extent of the subsurface contamination was not accurately mapped. Therefore, it was unknown at the time of the original estimate whether oil would be encountered or not.

Startup & Testing - Labor

Q. Please explain the cost variance for startup and testing labor.

A. An allowance of $1,640,000 is in place for startup and testing labor to be provided by Hawaiian Dredging and/or American Electric. This labor is to be provided as needed on a time and material cost basis. Based on the amount of labor that has been used to date for startup and testing, the actual cost for this area will probably be significantly below this amount.

COST MANAGEMENT

Q. How did Hawaiian Electric manage material costs for the CIP CT-1 Projects?

A. For the major pieces of equipment purchased by Hawaiian Electric, Hawaiian Electric used a competitive bid process to secure the lowest reasonable prices for materials. Hawaiian Dredging also competitively bid the equipment they were contracted to procure and passed on actual cost plus a 10% markup to Hawaiian Electric.

Q. How did Hawaiian Electric manage construction costs for the CIP CT-1 Projects?

A. Hawaiian Electric managed construction costs by going through a competitive bid selection process for vendors that met its qualification criteria. Also, following selection of the construction general contractor, Hawaiian Electric worked jointly with the engineering consultant and the general contactor to ensure the engineering design could be built in an efficient manner. Finally, Hawaiian Electric engaged in an open-book process with the construction contractor to ensure that the contract prices were reasonable.

Q. How was the construction contractor chosen?

A. In the past, Hawaiian Electric waited until the engineering design was approximately 80% to 90% complete prior to competitively bidding the construction work to construction contractors. However, for the CIP CT-1 Projects, it was decided to follow a different model for contracting the construction work. The model Hawaiian Electric used, which is being referred to as design-assist, started out by selecting a construction contractor to perform a design-assist role for the project. The selection was based on competitive open book[11] "target prices" for construction based on a project scope with about 10% of the engineering completed. Then, if the chosen contractor's final pricing (based on 90% engineering completed) was within 10% of their target price, then that contractor would be selected to construct the project. Otherwise, the construction contractor would be paid for only 50% of its work during the design phase and there would be no commitment to hire them for construction. The primary reasons for using this design-assist model were as follows:

- Potential for a shorter project schedule – this is very important since the HECO system was in a capacity shortfall situation and additional generation capacity was needed on the system as soon as possible
- Ensured that a contractor would be available to construct the project – the construction market at that time was very strong and contractors were turning down work opportunities. Also, construction at HELCO's Keahole Power Plant for ST-7 was expected to use a large amount of local resources during the same time period.
- The construction contractor became an integral part of the design team to help ensure constructability of design.
- Provided additional cost management tools through open book arrangement with the general contractor that may not have been available otherwise given the strong construction market at the time.
- Reduced the likelihood for change orders during the construction phase since the construction contractor is part of the design team.

To select the design-assist contractor, Hawaiian Electric contacted four

[11] With open book estimates, Hawaiian Electric was able to review the details of the contractor's estimate to verify that a reasonable price was being offered.

construction contractors that had experience with power plant construction and had recent experience doing heavy construction projects in Hawaii. Of these contractors, only two (Hawaiian Dredging and Kiewit) expressed interest in doing the work. The other two contractors (Brinderson and Global Integrated Services) declined to bid since they already had a high workload with other projects. Based on their proposals and target prices, Hawaiian Electric chose Hawaiian Dredging as the design-assist contractor.

Q. Are the construction costs for the generating station reasonable?

A. Yes, Hawaiian Electric believes that the construction costs for the generating station are reasonable for the scope of work. As mentioned above, Hawaiian Electric received competitive pricing from two construction contractors and chose the one with the lower overall pricing structure.

Q. What efforts were made to minimize the generating station construction costs?

A. In addition to competitively bidding the construction work as described above, significant efforts were made to minimize generating station construction costs, including:

1) HDCC performed their own competitive bidding for some of the major subcontracted work and passed on the savings to Hawaiian Electric. For example, HDCC bid out fuel tank and water tank construction to several tank construction firms. The pricing received from CBI was approximately $800,000 lower than what HDCC included in their original target price and HDCC passed on these savings to Hawaiian Electric.
2) Originally, HDCC planned to subcontract the stack construction work to CBI. However, upon receiving a bid from CBI, HDCC concluded that they could

erect the stack themselves for approximately $420,000 less. So, HDCC made the decision to self-perform this work and passed the savings on to Hawaiian Electric.

3) In HDCC's target cost estimate, they included approximately $1,400,000 for architectural services to design the buildings. After bidding this scope of work to local architectural firms, the best price they were able to get was around $2,000,000, which appeared to be a consequence of the booming construction market in Hawaii at the time. In an attempt to get a better price for Hawaiian Electric, HDCC asked an architectural firm out of Florida with whom HDCC had previously worked (BRPH) to provide a quote. BRPH's quote of $900,000 was significantly less than the local architectural firms and Hawaiian Dredging passed on this savings to Hawaiian Electric.

4) Normally, HDCC adds a 12% markup to subcontractor work to cover their management costs and profit. This amount and type of markup is a standard practice in the construction industry. However, since the subcontracted electrical work was such a large part of the overall construction costs (approximately $13,000,000), HDCC agreed upon Hawaiian Electric's request to limit their markup of the electrical subcontractor to 6%. This resulted in a savings to Hawaiian Electric of almost $800,000.

Q. Did Hawaiian Electric eliminate work scope to minimize generating station construction costs?

A. No, Hawaiian Electric did not eliminate work scope to reduce generating station construction costs. Eliminating work scope for this generating station would have resulted in a less reliable power plant, which could ultimately reduce system reliability and increase costs to the ratepayers. Hawaiian Electric utilizes prudent project cost management measures when installing critical infrastructure projects while maintaining high standards for reliability and operational flexibility. These high standards are necessary for an island utility with no interconnections to a back-up power grid in order to continue to provide reliable service.

Q. Did Hawaiian Electric have assistance in the development of the rough order-of-magnitude engineering and cost estimates for the CIP CT-1 Projects?

A. For the CIP CT-1 Projects, Hawaiian Electric hired Sargent & Lundy to complete the rough order-of-magnitude engineering design for the generation station and to provide a cost estimate for the project. Sargent & Lundy prepared a bottom-up method cost estimate for the CIP CT-1 Projects. The specific methodology that Sargent & Lundy used in developing its cost estimate is detailed in the supplemental testimony of Mr. Lunardini in HECO ST-17B. Hawaiian Electric adjusted this rough order-of-magnitude cost estimate for contingencies and to account for normal inflation.

SCHEDULE

Q. For each of the project components listed in HECO-S-17A01, which ones have already been placed in-service?

A. The project components that were already placed in-service are listed below along with their in-service dates:

- AES Substation (P0001051) – April 9, 2009
- CEIP Substation (P0001052) – April 22, 2009

- CIP Land (P0001084) – November 28, 2008[12]
- Microwave Communications (P0001135) – June 3, 2009
- Kalaeloa Relays (P0001137) – April 1, 2009

Q. For the project components listed in HECO-S-17A01 that have not yet been placed in-service, what is the estimated in-service date?

A. The estimated in-service dates for the remaining components are as follows:

- Generating Station (P4900000) – July 31, 2009
- Transmission Line (P0001050) – July 27, 2009
- Fiber Communication (P0001134) – July 27, 2009
- Kahe Breakers (P0001137) – August 31, 2009

Q. Are there any major subcomponents of the project components listed in HECO-S-17A01 that will not be completed by the estimated in-service dates listed above?

A. Yes, for the generating station component, there are two subcomponent systems that will not be completed by July 31, 2009. These two subcomponents are the blackstart generators and the water treatment system. There are no other subcomponent systems that will not be in-service by the dates listed above.

Q. What are the expected completion dates and costs for the blackstart diesels and water treatment subcomponents?

A. The following table shows the expected completion dates and costs for these subcomponents:

In-Service Dates and Costs for the Blackstart Diesel
Generators and Water Treatment System

	Expected In-Service Date	**Estimated Cost**

[12] Land does not technically get placed into service, but the last transaction for this component was signing the transmission line easement settlement agreement with Chevron on November 28, 2008.

Blackstart Generators	August 31, 2009	$3,000,000
Water Treatment System	October 31, 2009	$6,500,000
	Total	**$9,500,000**

Q. Will the later in-service date for the blackstart generators or the water treatment system prevent operation of the remaining portions of the generating station component?

A. No, the later in-service dates for these subcomponents will not affect the in-service date for the remaining portions of this component. The blackstart generators are only needed in the event of an island-wide blackout. So, the generating station will not have blackstart capability until these units go into service, but otherwise the generating station can operate as normal. Until the water treatment system is in-service, demineralized water needs at the generating station will be satisfied by trucking in water from one of the nearby independent power producers or from other Hawaiian Electric generating stations.

Q. What is the current schedule for the generating station?

A. As mentioned earlier, the generating station is expected to be in-service by July 31, 2009. This means that the combustion turbine-generator will be tied into the electrical grid and producing power. Approximately one week later, performance testing in accordance with the Siemens contract will occur to verify guaranteed levels of power output, heat rate, and emissions. Source testing, as required by the air permit within 60 days of full load capability, is scheduled to occur in late August 2009. Finally, a two-week reliability run is scheduled for late October or early November 2009.

Q. What is the reliability run test?

A. The reliability run test is a two-week test where the unit is run mostly continuously at higher loads. This test will use approximately 2 million gallons of fuel. Since fuel to the new generating station is being delivered by 8,000-gallon capacity trucks[13], waiting until later in the year will allow time to build up proper fuel inventories to complete the testing.

Q. Is waiting to complete the reliability test delaying the use of biodiesel?

A. No, it is not likely that a source of biodiesel for initial testing will be available prior to the planned dates for the reliability run. However, in the event that biodiesel will be available sooner than anticipated, Hawaiian Electric is currently attempting to build up a fuel inventory at the new generating station as fast as feasible so it can complete the reliability test run sooner. Also, Hawaiian Electric is currently trying to negotiate a contract modification with Siemens to exclude the reliability guarantee as one that will be deemed complete if biodiesel is used prior to the test run.

Q. What if the combustion turbine-generator does not meet the contractual performance guarantees?

A. If the guaranteed values for power output, heat rate, and reliability are not satisfied during the initial testing, Siemens can choose to take up to nine months to remedy the situation or pay Hawaiian Electric liquidated damages. At the end of the nine-month period, Siemens must pay Hawaiian Electric liquidated damages for guarantees that are still not met.

Q. What fuel will be used to complete these tests?

A. These performance and source tests must be completed using #2 diesel fuel. The

[13] If the intention was to run the generating unit long-term on #2 diesel, deliveries of this fuel would have been designed to be by pipeline. This would allow for quick deliveries of large volumes of fuel. However, since the long-term plan is to use biodiesel, it would not have been cost-effective to install a diesel fuel pipeline to the generating station.

contract with Siemens states that in the event Hawaiian Electric operates or attempts to operate the unit on biodiesel fuel prior to the unit successfully achieving the performance guarantees, the performance guarantees shall be deemed successfully achieved and satisfied for the unit. Therefore Hawaiian Electric intends to use only #2 diesel in the combustion turbine until all performance guarantees are met.

The unit is currently only fully permitted for use with #2 diesel. The current air quality permit allows the use of alternative renewable fuels, such as biodiesel, but only after certain emissions test data are provided to the Hawaii Department of Health for their review and the permit is subsequently modified to include that particular fuel. Therefore, Hawaiian Electric intends to use #2 diesel in the combustion turbine for the initial source test.

Q. When will biodiesel be used to fuel the combustion turbine?

A. Following successful achievement of all performance guarantees, Hawaiian Electric intends to conduct tests using biodiesel in order to obtain the emissions data necessary to modify the air permit. Once the permit is modified, the intention is to run the unit 100% on biodiesel.

Q. What fuel will be used to run the combustion turbine prior to receiving the air permit modification for biodiesel?

A. From the time the generating unit is place in-service until the air permit is modified, Hawaiian Electric is required to run the unit on regular #2 diesel, except for the special biodiesel emissions testing mentioned above. Therefore, Hawaiian Electric's intention during this time period is to run the unit on #2 biodiesel as necessary to meet the electrical demands on Oahu.

OVERVIEW OF
<u>POWER SUPPLY ENGINEERING'S COST ESTIMATING PROCESS</u>

<u>Development of Project Cost Estimates During Different Phases of a Project</u>

Q. How does the Hawaiian Electric Power Supply Engineering Department develop cost estimates for major projects?

A. First of all, Power Supply Engineering is responsible for engineering and managing projects involving Hawaiian Electric's generating stations for which capital expenditure applications pursuant to General Order No. 7, paragraph 2.3(g)(2) are required. Examples include new generating units, boiler control upgrades, and fuel oil tank improvements.

Project cost estimates are developed using several different approaches depending on the characteristics of the specific project and the phase of the project at which the project cost estimate is developed. A project cost estimate continues to be refined and updated as the project proceeds through the major phases of the project. In general terms, the major phases of a project can be identified as conceptual engineering, preliminary engineering, detailed engineering, procurement and construction,

Q. What are the characteristics of the engineering phases and how do these influence the accuracy of the cost estimates?

A During the conceptual engineering phase, which is sometimes called the project planning phase, the project scope is defined in very general terms such as a general plant arrangement. Based on this general information, a conceptual cost estimate is developed. Since very little engineering has been done at this point, there are a number of assumptions that are made with respect to the CIP CT-1

Projects.

During the next phase, the preliminary engineering phase, the project requirements and major equipment are identified and preliminary mechanical and electrical layouts are developed. With a preliminary design based on 5% to 10% of the engineering completed, many of the assumptions used in the rough order-of-magnitude cost estimate are refined and the project cost estimate is updated.

During the detailed engineering phase, the design scope is finalized and the cost estimate is updated based on preliminary piping and instrumentation drawings ("P&IDs"), electrical single line diagrams, equipment layouts, and preliminary cost estimates from major equipment vendors. Additional information such as preliminary estimates of installation and construction costs from mechanical and electrical contractors may also be obtained. With the completion of additional engineering, the accuracy of the project cost estimate can be further improved.

Q. When does Power Supply Engineering normally prepare the cost estimates that are submitted with the applications to the Commission?

A. For projects such as power plant projects that have very long lead times for permitting and regulatory approvals and where only a certain amount of engineering can take place before commitments need to be made for equipment and materials, the application with its cost estimate to be submitted to the Commission would be developed during the conceptual engineering phase.

Q. How does the actual purchase of equipment help with the accuracy of cost estimation and further refinement of engineering of the project?

A. As equipment contracts are awarded, equipment pricing becomes known with more certainty. There is then a time lag between equipment award and submittal of vendor drawings by the equipment suppliers. These vendor drawings determine foundation sizes, and the size and amount of interfacing piping, instrumentation, valves, cable, conduit, and plant services required to operate the purchased equipment. Once these requirements are known, the designs for foundations, buildings, instrumentation, control systems, piping, cable, duct banks, and conduits can be completed. After these designs are completed, material costs and construction labor can be estimated with greater accuracy.

<u>Methods Used To Develop Cost Estimates</u>

Q. What are the different methods used by Power Supply Engineering to develop cost estimates?

A. Depending on the scope and schedule for a project, similarity to past projects, and the phase of the project, there are different methods that can be used to develop project cost estimates.

Q. What methods are used to develop cost estimates for larger more complex projects?

A. For large complex projects, a "bottom-up" method can be used where estimated quantities of piping, valves, conduits, wiring, concrete, structural steel, excavation quantities, etc. are determined and unit prices are applied. These costs are then totaled to give the total project cost estimate. If this approach is used early in a project, numerous assumptions need to be made on the quantities of materials and the accuracy of these assumptions impacts the accuracy of the overall cost estimate. As more engineering is completed and more information on the quantities becomes available, the accuracy of the cost estimate is improved.

Q. Can consultant databases be used to estimate projects?

A. Yes. If a project requires consultant services to support the design and construction of a project, their estimating package utilizing their database is used to calculate the project cost since their estimating database usually has significantly more cost data for similar or compatible equipment being installed. Based on the construction business climate and other market conditions in Hawaii, those cost estimates are reviewed with the consultant and adjusted as appropriate to reflect Hawaii specific factors.

Factors that Cause Costs to Vary from Estimates

Q. Please describe the factors that can cause the actual project costs to vary from the estimated project cost.

A. There are many factors that may cause the actual project cost to vary from the estimated project cost. These include permitting and regulatory approvals, schedule changes, work scope changes, commodity prices, limited availability of skilled craft labor, construction industry conditions, general market conditions, and escalation.

Q. How can permitting and regulatory approvals change costs?

A. There are two issues that affect capital project costs due to permitting. First, permitting approval time period is very difficult to determine due to federal, state, and county agencies work loads and interveners who participate in the permitting process. Delays in the permitting processes cause delays in Hawaiian Electric's ability to commit and firm up equipment pricing since equipment will not be purchased until all major discretionary permits have been approved. Second, permitting may also include conditions, established by the approving agency, that were not anticipated and which may increase project scope and costs.

Q. How can schedule changes impact actual costs?

A. During the conceptual design phase, an in-service date is assumed for the project and then a high level activity schedule including permitting, engineering design, procurement, and construction is developed. During preliminary engineering, the schedule for each activity is broken down further, linkages between activities are identified, and the critical path for the project is determined. Even during preliminary engineering, all information required to develop a project schedule will not be available. Assumptions such as permit approval times, equipment delivery, and construction lead times need to be made to develop the project schedule. If the actual schedule differs from the assumed schedule, this may lead to a variance in the project costs since changes in schedule can affect project costs.

For example, allowance for funds used during construction ("AFUDC") cost has a direct correlation with the schedule. A longer schedule can increase AFUDC, while a shorter schedule can reduce AFUDC. Permitting schedule delays prevent Hawaiian Electric from firming up equipment costs that are subject to inflation and commodity cost fluctuation. Delays in equipment delivery due to natural disasters, strike, damaged equipment, or any other unforeseen problem will increase project cost due to labor and construction equipment commitments scheduled by the contractors and consultant to complete the work on time.

Q. How do work scope changes cause costs to vary from original estimates?

A. When a project estimate is developed based on rough order-of-magnitude or preliminary ~~10%~~ engineering design, assumptions are made based on information from preliminary drawings, site visits, and project team experience. As detailed information is obtained from consultant's detailed design, vendors' proposals, and existing site conditions, the assumptions are either verified or the project scope is modified, as necessary. Project scope changes may be due to the availability of new technology that was not considered, changes in purchased equipment requirements and dimensions, differences in actual site conditions (e.g., soil conditions or underground obstructions), new operational or maintenance requirements, and new environmental regulations. Scope changes can either increase or decrease the actual project costs.

Q. How do commodity prices cause variances from project estimates?

A. Commodity prices for goods such as fuel oil, copper, steel, and stainless steel fluctuate and are very difficult to predict, especially for two to three years in the future. Due to uncertainties in forecasting commodity prices in the project costs, Power Supply Engineering uses escalation factors for estimating future costs, including commodity prices. During this decade, commodity prices were rising so fast, even cable suppliers could not predict commodity prices and would not provide firm quotes that were good for more than two weeks.

Q. What impacts can availability of skilled craft labor have on actual costs?

A. For power plant construction work, there is a limited number of skilled craft laborers in Hawaii. If there are other industrial projects that are active and that occur at about the same time as a power plant project, skilled craft laborers would need to be imported from the mainland, which would increase costs due to higher transportation costs and per diem expenses for these mainland laborers.

Since construction for power plant projects can start two to three years after the application is submitted to the Commission, it is difficult to forecast if other industrial projects will be active during the same time period. Private industries are not required to report their plans for major projects. For estimating purposes, assumptions are made that the majority of the work will be done by local skilled labor.

Q. How can market conditions affect variances from project cost estimates?

A. Due to limited numbers of licensed contractors with experience to perform heavy industrial work in Hawaii, competition is limited. Presently there is only one electrical contractor that has a license to perform high voltage work and only a few mechanical contractors financially strong and stable to provide services to construct major power plant projects. Since the local contractors have a limited amount of local personnel to perform heavy construction work in Hawaii, they have occasionally declined to submit bids on utility projects during periods of extensive construction activities. Alternatively, instead of declining to bid, contractors may add a premium to their bid to maximize their return on the work, and to eliminate any risk to themselves in their proposal. Since construction market conditions are difficult to predict when the initial project cost estimates are developed, assumptions are made that Hawaiian Electric will receive competitive quotes for the project that reflect normal market conditions.

Q. How does escalation cause cost variances?

A. Since heavy industrial work in Hawaii is limited and infrequent, there is no industrial work escalation index available for Hawaii. There are escalation indices available for U.S. mainland regions, however Hawaii is unique due to being an island economy and isolated from the mainland. The physical separation from the mainland prevents contractors from moving freely from the mainland to Hawaii to promote competition, limits freight/transportation options to Hawaii, limits the number of equipment vendors available in Hawaii, and increases contractors' and consultants' overhead costs due to a higher cost of living on the islands. All of these factors result in actual Hawaii escalation rates that are different than the escalation indices developed for the mainland. One approach to address these differences is to use a standard escalation index for the U.S. mainland and adjust it for Hawaii specific factors. Cost variances result when the changes in actual costs differ from the escalation rates assumed in the original cost estimate.

<u>Development of Cost Estimate for CIP CT-1 Generating Station Project</u>

Q. How were the original cost estimates for the CIP projects developed?

A. In Docket No. 05-0145, Hawaiian Electric requested approval to commit funds for the purchase and installation of the CIP Projects. The Commission approved Hawaiian Electric's application in Decision and Order No. 23457 ("D&O 23457"), filed May 23, 2007.

For the CIP CT-1 Projects, Hawaiian Electric hired Sargent & Lundy to complete the conceptual engineering design for the generating station and to provide a cost estimate for the project. Sargent & Lundy prepared a bottom-up method cost estimate for the CIP CT-1 Projects. The specific methodology that Sargent & Lundy used in developing their cost estimate is detailed in the testimony of Mr. Lunardini (HECO ST-17B). To this estimate, a 10% adjustment was made for material costs and a 32% adjustment was made for labor costs.

Finally, inflation factors were applied to these estimates to account for normal inflation between the time the estimate was done and the time actual material purchases were made and construction contracts were signed. The inflation factors came out of Hawaiian Electric's estimating program, Pillar, and were in the order of 3% to 4% per year.

SUMMARY

Q. Please summarize your supplemental testimony.

A. As discussed earlier in my supplemental testimony, given the generation reserve shortfall identified as early as 1993 in the Company's first integrated resource plan ("IRP-1"), and other filings identifying continued generation reserve shortfall, as more fully discussed in Mr. Sakuda's supplemental testimony, HECO ST-4, coupled with the long lead time for power generation project, the Company submitted its application for CIP CT-1 with the intend of remedying the generation reserve shortfall situation as soon as practicable.

As with any large complex project, cost estimations are based on assumptions and parameters available at the time of the initial cost estimation. During the implementation period, actual costs are influenced by (1) actual market conditions which directly affect the actual costs for labor and materials, (2) site conditions as revealed by actual sampling and testing analyses and results, (3) world-wide supply and demand of commodity prices, (4) construction costs reflecting changes in specifications and requirements, and (5) requirements for the requisite governmental agencies approvals.

Q. In the CIP CT-1 projects, what are the cost areas most impacted by these factors?

A. Most of the project cost increases above the original estimate are caused by the material costs and construction costs for CIP CT-1 being higher than originally estimated. These two categories account for $53,000,000 of the $55,700,000 difference, or 96% of the increase.

Q. Could these cost increases be reasonable anticipated at the time of the original cost estimation process?

A. No. At discussed above and in Mr. Lunardini's supplemental testimony, HECO ST-17B, there are many factors outside of the control of the Company which affected this project's cost, including (1) increases in commodity prices due to global supply and demand situation, (2) availability of local skilled labor pool, (3) Hawaii's construction market condition during the time of construction, (4) changes in specifications due to actual site conditions and requirements of the actual equipment ordered, and (5) changes in transportation costs due to hyper fuel oil price increases.

Q. Does this conclude your testimony?

A. Yes, it does.

HAWAIIAN ELECTRIC COMPANY INC.

ROBERT C. ISLER, P.E.

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. 820 Ward Avenue P. O. Box 2750 Honolulu, HI 96840
Position:	Project Manager Power Supply Engineering Department
Education:	Bachelor of Science in Mechanical Engineering Virginia Polytechnic Institute & State University, 1987
Other Qualifications:	Licensed Professional Engineer State of Hawaii, Mechanical Branch - 1998
Experience:	<u>HAWAIIAN ELECTRIC COMPANY, INC.</u>
	2000 - present Project Manager Power Supply Engineering Department (post September 2004) Planning & Engineering Department, Hawaiian Electric Company, Inc.
	1998 - 2000 Mechanical Engineer II, Planning & Engineering Department, Hawaiian Electric Company, Inc.
	1993 - 1998 Designer II, Planning & Engineering Department Engineering Department, Hawaiian Electric Company, Inc.
	<u>OTHER</u>
	1987 - 1992 Submarine Officer, United States Navy

Total Estimated Cost for the CIP Generation Addition and Transmission Additions Projects (Y-49000)
Amount Approved in Docket 05-0145 Decision & Order

Project Component	HECO Labor Non-Construction	HECO Labor - Construction	Materials	Outside Services - Consultant Services	Outside Services - Construction	Overheads	Land	AFUDC	Component Totals
P4900000 - Generating Station	$1,017,096	$0	$50,110,498	$10,789,815	$41,572,722	$1,860,993	$0	$10,048,102	$115,399,225
P0001050 - Transmission Line	$184,138	$321,782	$2,228,484	$1,044,740	$1,000,986	$850,300	$0	$577,084	$6,207,513
P0001051 - AES Substation	$131,370	$210,175	$666,060	$804,756	$270,412	$496,556	$0	$257,817	$2,837,146
P0001052 - CEIP Substation	$52,170	$64,963	$232,400	$87,615	$29,000	$171,488	$0	$48,975	$686,611
P0001084 - CIP Land	$0	$0	$0	$0	$0	$0	$9,070,000	$0	$9,070,000
P0001134 - Fiber Communications	$41,371	$4,620	$75,288	$0	$45,841	$64,177	$0	$14,606	$245,903
P0001135 - Microwave Comms	$47,472	$14,186	$180,707	$36,444	$21,649	$92,942	$0	$28,479	$421,880
P0001136 - Kahe Breakers	$129,468	$247,703	$898,700	$200,000	$45,760	$567,409	$0	$180,691	$2,269,731
P0001137 - Kalaeloa Relays	$28,471	$31,941	$99,200	$30,000	$0	$86,257	$0	$16,382	$292,251
Category Totals	$1,631,555	$895,371	$54,491,337	$12,993,370	$42,986,370	$4,190,123	$9,070,000	$11,172,136	$137,430,260

Total Estimated Cost for the CIP Generation Addition and Transmission Additions Projects (Y-49000)
Current Cost Estimate

Project Component	HECO Labor Non-Construction	HECO Labor - Construction	Materials	Outside Services - Consultant Services	Outside Services - Construction	Overheads	Land	AFUDC	Component Totals
P4900000 - Generating Station	$1,911,926	$0	$64,835,507	$11,320,216	$80,087,749	$2,884,248	$0	$8,810,481	$169,850,127
P0001050 - Transmission Line	$138,919	$496,625	$3,251,192	$471,825	$1,739,899	$1,156,550	$0	$303,284	$7,558,293
P0001051 - AES Substation	$153,574	$391,166	$782,459	$1,125,331	$372,039	$861,342	$0	$198,838	$3,884,748
P0001052 - CEIP Substation	$30,408	$87,794	$215,939	$0	$12,090	$216,381	$0	$19,903	$582,515
P0001084 - CIP Land	$0	$0	$0	$0	$0	$0	$7,912,636	$0	$7,912,636
P0001134 - Fiber Communications	$40,331	$89,686	$78,823	$24,631	$36,772	$238,698	$0	$12,021	$520,962
P0001135 - Microwave Comms	$38,651	$27,073	$186,250	$54,153	$217,658	$152,120	$0	$20,637	$696,542
P0001136 - Kahe Breakers	$42,384	$281,112	$662,201	$144,205	$0	$620,428	$0	$136,060	$1,886,389
P0001137 - Kalaeloa Relays	$18,222	$36,705	$65,983	$0	$0	$97,079	$0	$8,643	$226,631
Category Totals	$2,374,416	$1,410,161	$70,078,354	$13,140,361	$82,466,206	$6,226,845	$7,912,636	$9,509,866	$193,118,844

Cost Differences between Current Estimate and D&O Approved Amount (Current - Approved)

Project Component	HECO Labor Non-Construction	HECO Labor - Construction	Materials	Outside Services - Consultant Services	Outside Services - Construction	Overheads	Land	AFUDC	Component Totals
P4900000 - Generating Station	$894,830	$0	$14,725,010	$530,401	$38,515,027	$1,023,255	$0	($1,237,621)	$54,450,901
P0001050 - Transmission Line	($45,219)	$174,843	$1,022,708	($572,915)	$738,912	$306,250	$0	($273,800)	$1,350,779
P0001051 - AES Substation	$22,204	$180,991	$116,399	$320,575	$101,627	$364,786	$0	($58,979)	$1,047,601
P0001052 - CEIP Substation	($21,762)	$22,831	($16,461)	($87,615)	($16,910)	$44,893	$0	($29,072)	($104,096)
P0001084 - CIP Land	$0	$0	$0	$0	$0	$0	($1,157,364)	$0	($1,157,364)
P0001134 - Fiber Communications	($1,039)	$85,066	$3,535	$24,631	($9,069)	$174,520	$0	($2,585)	$275,059
P0001135 - Microwave Comms	($8,821)	$12,886	$5,543	$17,709	$196,009	$59,178	$0	($7,842)	$274,662
P0001136 - Kahe Breakers	($87,084)	$33,409	($236,499)	($55,795)	($45,760)	$53,019	$0	($44,631)	($383,342)
P0001137 - Kalaeloa Relays	($10,249)	$4,764	($33,217)	($30,000)	$0	$10,821	$0	($7,739)	($65,619)
Category Totals	$742,860	$514,790	$15,587,016	$146,991	$39,479,836	$2,036,722	($1,157,364)	($1,662,269)	$55,688,582

P4900000 - Generating Station

LINE ITEM		ESTIMATED PROJECT COSTS - RATE CASE	ESTIMATE - 7/12/09	Difference Current - Original
HECO LABOR - NON CONSTRUCTION		**$1,017,096**	**$1,911,926**	**$894,830**
MATERIALS		**$50,110,498**	**$64,835,507**	**$14,725,010**
Chemical Equipment		**$4,851,800**	**$4,631,468**	**$220,332**
Water Treating		$4,851,800	$4,631,468	$220,332
Control Equipment		**$769,552**	**$1,525,503**	**$755,951**
Distributed Control System		$452,678	$831,629	$378,951
Continuous Emissions Monitors		$256,517	$326,092	$69,575
Field Mounted Instruments with Racks		$60,357	$367,782	$307,425
Electrical Equipment		**$3,211,143**	**$6,877,457**	**$3,666,314**
Generator Circuit Breakers		$550,758	$520,285	$30,473
Main Power & Auxiliary Transformers		$1,373,122	$3,198,042	$1,824,920
Main Power Transformer	$1,100,000		$2,251,485	$1,151,485
Auxiliary Transformer	$273,122		$570,370	$297,248
Backup Transformer	$0		$260,799	$260,799
Control/Admin Bldg Transformer	$0		$115,388	$115,388
4160V Switchgear		$264,062	$1,462,140	$1,198,078
Iso-Phase Bus		$172,017	$367,739	$195,722
480V Switchgear with MCCs		$407,410	$138,754	$268,656
Non-Seg and Cable Bus		$37,723	$114,655	$76,932
125VDC Batteries, Chargers & UPS		$120,714	$299,502	$178,788
48VDC Batteries		$0	$12,775	$12,775
48VDC Charger		$0	$3,885	$3,885
High Voltage Cable		$285,337	$647,534	$362,196
Line Protection Relay Panel		$0	$32,205	$32,205
Xfmr Protection Relay Panel		$0	$39,700	$39,700
RTU		$0	$40,242	$40,242
Mechanical Equipment		**$40,114,779**	**$48,024,668**	**$7,909,889**
CT with Accessories		$33,675,947	$40,447,307	$6,771,360
Fire Pumps		$286,696	$252,844	$33,852
Miscellaneous Pumps		$142,593	$184,317	$41,724
Sump Pumps		$36,214	$141,184	$104,970
Well Water Pumps		$0	$217,810	$217,810
Supply and Injection Wells		$829,909	$838,454	$8,545
Shop Fabricated Tanks		$80,727	$60,611	$20,116
Fuel Oil Conditioning System		$452,678	$0	$452,678
Air Compressors & Dryers		$105,625	$560,578	$454,953
Oil Water Seperator		$64,129	$165,261	$101,132
Large Bore Piping		$681,790	$1,021,310	$339,520
Control Valves & Specialties		$47,984	$1,369,243	$1,321,259
Diesel Generator (Blackstart)		$3,710,488	$2,765,749	$944,739
Miscellaneous Equipment		**$0**	**$1,076,412**	**$1,076,412**
Shop Equipment		$0	$170,000	$170,000
Furniture		$0	$180,000	$180,000
Security Cameras		$0	$156,137	$156,137
Guard Shack		$0	$26,844	$26,844
Card Reader Hardware		$0	$37,382	$37,382
Comm Equipment		$0	$54,886	$54,886
IT Equipment		$0	$104,120	$104,120
Trailer		$0	$59,025	$59,025
Phone Equipment		$0	$20,033	$20,033
Signs		$0	$1,198	$1,198
Fuel Tank Gauge Door		$0	$3,336	$3,336
Constrol System Monitors		$0	$1,164	$1,164
Fuel Unloading Fittings		$0	$796	$796
Water Hose & Fittings		$0	$3,319	$3,319
Radios		$0	$6,882	$6,882

Flanges & Gaskets	$0	$655	$655
Unaccounted for Costs	$0		$0
Miscellaneous	$0	$250,635	$250,635
Spare Parts	**$967,969**	**$2,700,000**	**$1,732,031**
Structural Equipment	**$195,255**	**$0**	**$195,255**
Structural Steel	$180,166	$0	$180,166
Cranes and Hoists	$15,089	$0	$15,089
OUTSIDE SERVICES - CONSULTANT SERVICES	**$10,789,815**	**$11,320,216**	**$530,401**
Air Permit Consultant	**$100,000**	**$0**	**$100,000**
Air Quality Monitoring Consultant	**$386,428**	**$100,000**	**$286,428**
Construction Management	**$1,946,998**	**$1,205,102**	**$741,896**
Startup & Commissioning	**$0**	**$1,656,920**	**$1,656,920**
Engineering Consultants	**$2,719,238**	**$4,475,400**	**$1,756,162**
Environmental Consultant - Air (Jim Clary)	**$498,954**	**$628,961**	**$130,007**
Environmental Consultant - BACT	**$58,200**	**$89,113**	**$30,913**
General Services	**$4,032,786**	**$2,160,654**	**$1,872,132**
Legal	**$371,448**	**$603,407**	**$231,959**
Permitting Consultants	**$675,762**	**$400,659**	**$275,103**
OUTSIDE SERVICES - CONSTRUCTION	**$41,572,722**	**$80,087,749**	**$38,515,027**
Hawaiian Dredging	**$41,572,722**	**$78,323,818**	**$36,751,096**
HDCC- Civil/Structural	**$7,882,068**	**$16,056,611**	**$8,174,543**
Substructure Installation, Foundations & Ductruns	$3,935,554	$8,385,532	$4,449,978
Steel and Gallery Installation	$130,766	$0	$130,766
Civil Work	$3,591,471	$6,710,858	$3,119,387
Painting	$98,352	$829,827	$731,475
Demolition	$125,925	$130,394	$4,469
HDCC- Electrical	**$4,168,742**	**$6,742,005**	**$2,573,263**
Electrical Major Equipment Installation	$839,298	$1,056,955	$217,657
Electrical BOP Installation	$3,200,740	$5,540,052	$2,339,312
HV Lines to Substation	$128,704	$144,998	$16,294
HDCC- Furnish & Erect	**$8,631,759**	**$16,698,074**	**$8,066,315**
Field Erected Tanks	$3,631,193	$5,850,100	$2,218,907
Fire Protection	$663,232	$368,471	$294,761
Buildings	$4,337,334	$10,479,503	$6,142,169
HDCC- I&C	**$242,268**	**$395,465**	**$153,197**
Instrument & Controls Installation	$242,268	$395,465	$153,197
HDCC- Mechanical	**$7,728,162**	**$13,867,075**	**$6,138,913**
Combustion Turbine Erection	$2,216,440	$5,430,683	$3,214,243
Fuel Conditioning Installation	$90,790	$0	$90,790
Bulk Gas Storage Installation	$28,047	$0	$28,047
BOP Equipment Installation	$298,929	$233,673	$65,256
BOP Piping, Valves & Specialties Installation	$4,213,992	$5,474,605	$1,260,613
Exhaust Stack Construction	$385,854	$1,616,698	$1,230,844
Cranes & Hoists	$5,709	$0	$5,709
Water Treatment	$488,401	$1,111,416	$623,015
HDCC - Off-Site Storage/Trailers	**$0**	**$470,309**	**$470,309**
HDCC - Indirects	**$7,640,212**	**$11,808,000**	**$4,167,788**
HDCC - GA & Profit	**$5,279,511**	**$7,132,250**	**$1,852,739**
HDCC - Change Orders	**$0**	**$5,154,029**	**$5,154,029**
Pacific Commercial Services	**$0**	**$6,963**	**$6,963**
Philip Services	**$0**	**$103,208**	**$103,208**
Haztech	**$0**	**$15,958**	**$15,958**
Startup & Testing - Labor	**$0**	**$1,637,801**	**$1,637,801**
OVERHEADS	**$1,860,993**	**$2,884,248**	**$1,023,255**
AFUDC	**$10,048,102**	**$8,810,481**	**$1,237,621**
TOTAL	***$115,399,226***	***$169,850,127***	**$54,450,901**

P0001050 - Transmission Line

LINE ITEM	ESTIMATED PROJECT COSTS - RATE CASE	ESTIMATE - 7/12/09	Difference Current - Original
HECO LABOR - NON CONSTRUCTION	**$184,138**	**$138,919**	**($45,219)**
HECO LABOR - CONSTRUCTION	**$321,782**	**$496,625**	**$174,843**
MATERIALS	**$2,228,484**	**$3,251,192**	**$1,022,708**
Outside Material Cost - Steel Pole/Pole Framing/Conductor	**$2,225,877**	**$3,106,133**	**$880,255**
Steel Poles	$1,858,975	$2,742,751	$883,776
Pole Framing	$139,623	$57,232	($82,391)
Conductor, OPGW	$218,875	$221,800	$2,926
Splice Box	$8,405	$5,723	($2,682)
Miscellaneous	$0	$78,626	$78,626
Stock Material Cost - 46kV Underbuild Framing	**$2,606**	**$145,059**	**$142,453**
OUTSIDE SERVICES - CONSULTANT SERVICES	**$1,044,740**	**$471,825**	**($572,915)**
Outside Services - Construction Management	$90,924	$75,000	($15,924)
Outside Services - Sargent & Lundy	$859,583	$302,971	($556,612)
CSA - Soils Investigation - Outside Consultant	$53,061	$83,788	$30,728
General Services	$41,172	$10,066	($31,106)
OUTSIDE SERVICES - CONSTRUCTION	**$1,000,986**	**$1,739,899**	**$738,912**
Pole Foundations	$1,000,986	$1,348,836	$347,850
General Services	$0	$195,531	$195,531
OVERHEADS	**$850,300**	**$1,156,550**	**$306,250**
AFUDC	**$577,084**	**$303,284**	**($273,800)**
TOTAL	***$6,207,514***	***$7,558,293***	***$1,350,779***

P0001051 - AES Substation

LINE ITEM	ESTIMATED PROJECT COSTS - RATE CASE	ESTIMATE - 7/12/09	Difference Current - Original
HECO LABOR - NON CONSTRUCTION	**$131,370**	**$153,574**	**$22,204**
HECO LABOR - CONSTRUCTION	**$210,175**	**$391,166**	**$180,991**
MATERIALS	**$666,060**	**$782,459**	**$116,399**
Electrical - Outside Material Cost	**$654,060**	**$708,850**	**$54,790**
Potential Transformers	$19,800	$69,106	$49,306
PT Junction Box	$0	$2,709	$2,709
Gas Circuit Breakers	$346,500	$258,042	($88,458)
Disconnect Switches, 138kV	$73,260	$76,307	$3,047
Line Protection Relay Panels	$154,000	$104,759	($49,241)
Breaker Control Panel	$38,500	$34,284	($4,216)
Battery Charger	$3,300	$0	($3,300)
Battery Set with Rack	$7,700	$0	($7,700)
Bus Connectors, 138kV	$11,000	$43,193	$32,193
Surge Arrestors	$0	$3,078	$3,078
RTU Migration Package	$0	$29,410	$29,410
Miscellaneous	$0	$33,823	$33,823
Construction	$0	$54,139	$54,139
Electrical - Stock Material Cost	**$11,000**	**$73,561**	**$62,561**
Blueprints/Copies	**$1,000**	**$48**	**($952)**
OUTSIDE SERVICES - CONSULTANT SERVICES	**$804,756**	**$1,125,331**	**$320,575**
Outside Services - Construction Management	$54,082	$49,932	($4,150)
Outside Services - Engineering	$750,674	$1,063,130	$312,456
General Services		$12,269	$12,269
OUTSIDE SERVICES - CONSTRUCTION	**$270,412**	**$372,039**	**$101,627**
OVERHEADS	**$496,556**	**$861,342**	**$364,786**
AFUDC	**$257,817**	**$198,838**	**($58,979)**
TOTAL	**$2,837,146**	**$3,884,748**	**$1,047,601**

P0001052 - CEIP Substation

LINE ITEM	ESTIMATED PROJECT COSTS - RATE CASE	ESTIMATE - 7/12/09	Difference Current - Original
HECO LABOR - NON CONSTRUCTION	**$52,170**	**$30,408**	**($21,762)**
HECO LABOR - CONSTRUCTION	**$64,963**	**$87,794**	**$22,831**
MATERIALS	**$232,400**	**$215,939**	**($16,461)**
Electrical - Outside Material Cost	**$221,000**	**$192,637**	**($28,363)**
Potential Transformer	$19,800	$36,739	$16,939
Gas Circuit Breaker	$115,500	$87,177	($28,323)
Line Protection Relay Panels	$77,000	$32,011	($44,989)
Breaker Failure Relay	$5,500	$13,647	$8,147
Reclose Control Switch	$1,320	$0	($1,320)
Reclose Relay	$1,880	$0	($1,880)
Miscellaneous	$0	$15,453	$15,453
Construction		$7,610	$7,610
Electrical - Stock Material Cost	**$11,000**	**$23,302**	**$12,302**
Blueprints/Copies	**$400**	**$0**	**($400)**
OUTSIDE SERVICES - CONSULTANT SERVICES	**$87,615**	**$0**	**($87,615)**
Outside Services - Construction Management	$5,801	$0	($5,801)
Outside Services - Engineering	$81,814	$0	($81,814)
OUTSIDE SERVICES - CONSTRUCTION	**$29,000**	**$12,090**	**($16,910)**
OVERHEADS	**$171,488**	**$216,381**	**$44,893**
TRANSPORTATION	**$0**	**$33**	**$33**
AFUDC	**$48,975**	**$19,903**	**($29,072)**
TOTAL	**$686,611**	**$582,548**	**($104,063)**

P0001084 - CIP Land

LINE ITEM	ESTIMATED PROJECT COSTS - RATE CASE	ESTIMATE - 7/12/09	Difference Current - Original
LAND	**$9,070,000**	**$7,912,636**	**($1,157,364)**
Property Adjacent to Tank Farm	**$2,900,000**	**$3,071,636**	**$171,636**
44-Wide Easement		$1,261,761	$1,261,761
Substation Expansion Parcel		$1,809,875	$1,809,875
Transmission Line Easements	**$6,170,000**	**$4,841,000**	**($1,329,000)**
Campbell Easement		$636,000	$636,000
Chevron Easement		$4,205,000	$4,205,000
TOTAL	**$9,070,000**	**$7,912,636**	**($1,157,364)**

P0001134 - Fiber Communications

LINE ITEM	ESTIMATED PROJECT COSTS - RATE CASE	ESTIMATE - 7/12/09	Difference Current - Original
HECO LABOR - NON CONSTRUCTION	**$41,371**	**$40,331**	**($1,039)**
HECO LABOR - CONSTRUCTION	**$4,620**	**$89,686**	**$85,066**
MATERIALS	**$75,288**	**$78,823**	**$3,535**
Outside Materials	$75,288	$78,823	$3,535
Stock	$0	$3,971	$3,971
OUTSIDE SERVICES - CONSULTANT SERVICES	**$0**	**$24,631**	**$24,631**
OUTSIDE SERVICES - CONSTRUCTION	**$45,841**	**$36,772**	**($9,069)**
OVERHEADS	**$64,177**	**$238,698**	**$174,520**
AFUDC	**$14,606**	**$12,021**	**($2,585)**
TOTAL	**$245,903**	**$520,962**	**$275,059**

P0001135 - Microwave Comms

LINE ITEM	ESTIMATED PROJECT COSTS - RATE CASE	ESTIMATE - 7/12/09	Difference Current - Original
HECO LABOR - NON CONSTRUCTION	$47,472	$38,651	($8,821)
HECO LABOR - CONSTRUCTION	$14,186	$27,073	$12,886
MATERIALS	$180,707	$186,250	$5,543
OUTSIDE SERVICES - CONSULTANT SERVICES	$36,444	$54,153	$17,709
OUTSIDE SERVICES - CONSTRUCTION	$21,649	$217,658	$196,009
OVERHEADS	$92,942	$152,120	$59,178
OTHER	$0	$2,105	$2,105
TRANSPORTATION	$0	$9	$9
AFUDC	$28,479	$20,637	($7,842)
TOTAL	**$421,880**	**$698,656**	**$276,776**

P0001136 - Kahe Breakers

LINE ITEM	ESTIMATED PROJECT COSTS - RATE CASE	ESTIMATE - 7/12/09	Difference Current - Original
HECO LABOR - NON CONSTRUCTION	**$129,468**	**$42,384**	**($87,084)**
HECO LABOR - CONSTRUCTION	**$247,703**	**$281,112**	**$33,409**
MATERIALS	**$898,700**	**$662,201**	**($236,499)**
Electrical - Outside Material Cost	**$887,700**	**$584,232**	**($303,468)**
Potential Transformer	$13,200	$0	($13,200)
PT Junction Box	$5,500	$0	($5,500)
Gas Circuit Breakers	$693,000	$580,231	($112,769)
Breaker Control Panels	$176,000	$0	($176,000)
Miscellaneous	$0	$15,001	$15,001
Electrical - Stock Material Cost	**$11,000**	**$77,969**	**$66,969**
OUTSIDE SERVICES - CONSULTANT SERVICES	**$200,000**	**$144,205**	**($55,795)**
Electrical - Outside Engineering	$200,000	$144,205	($55,795)
OUTSIDE SERVICES - CONSTRUCTION	**$45,760**	**$0**	**($45,760)**
OVERHEADS	**$567,409**	**$620,428**	**$53,019**
AFUDC	**$180,691**	**$136,060**	**($44,631)**
TOTAL	**$2,269,731**	**$1,886,389**	**($383,342)**

P0001137 - Kalaeloa Relays

LINE ITEM	ESTIMATED PROJECT COSTS - RATE CASE	ESTIMATE - 7/12/09	Difference Current - Original
HECO LABOR - NON CONSTRUCTION	**$28,471**	**$18,222**	**($10,249)**
HECO LABOR - CONSTRUCTION	**$31,941**	**$36,705**	**$4,764**
MATERIALS	**$99,200**	**$65,983**	**($33,217)**
Outside Material Cost	$88,000	$39,474	($48,526)
RTU Migration	$0	$19,840	$19,840
Electrical - Stock Material Cost	$11,000	$1,802	($9,198)
Construction Materials	$0	$4,867	$4,867
Blueprints/Copies	$200	$0	($200)
OUTSIDE SERVICES - CONSULTANT SERVICES	**$30,000**	**$0**	**($30,000)**
OVERHEADS	**$86,257**	**$97,079**	**$10,821**
AFUDC	**$16,382**	**$8,643**	**($7,739)**
TOTAL	**$292,251**	**$226,631**	**($65,619)**

Summary Table of Cost Variances for CIP CT-1 Generation Project
Comparison of Original and Final Material Cost Estimates ($1,000s)

Item	Original Estimate	Current Estimate	Diff. $	Category (see explanations below table)
Water Treatment System	$4,852	$4,631	-$221	1
Blackstart Generators	$3,710	$2,766	-$945	1
Shop Tanks	$81	$61	-$20	2
Generator Circuit Breaker	$551	$520	-$31	2
Combustion Turbine	$33,676	$40,447	$6,771	3
Transformers	$1,373	$3,198	$1,825	3
DCS	$453	$832	$379	3
High Voltage Cable	$285	$648	$363	3
Isophase Bus	$172	$368	$196	3
Batteries, UPS, Chargers	$121	$316	$195	3
Oil/Water Separator	$64	$165	$101	3
Non-Segmented Bus Duct	$38	$115	$77	3
Continuous Emissions Monitor	$257	$326	$69	3
Spare Parts	$968	$2,700	$1,732	4
Valves & Specialties	$48	$1,369	$1,321	4
Switchgear & MCCs	$671	$1,601	$930	4
Air Compressors	$106	$561	$455	4
Large Bore Piping	$682	$1,021	$340	4
Field Instruments	$60	$368	$308	4
Supply & Injection Wells	$830	$1,056	$226	4
Pumps	$466	$578	$112	4
Miscellaneous - Allowance	$0	$251	$251	5
Security Equipment	$0	$220	$220	5
Furniture	$0	$180	$180	5
Shop Equipment	$0	$170	$170	5
IT, Phone & Communications	$0	$124	$124	5

Protective Relay Panels – CIP	$0	$72	$72	5
Trailer	$0	$59	$59	5
Power Plant Communications	$0	$55	$55	5
Remote Terminal Unit	$0	$40	$40	5
Miscellaneous	$0	$17	$17	5
Structural Equipment	$195	$0	6	6
Fuel Conditioning Equipment	$453	$0	-$453	6
TOTALS	**$50,110**	**$64,836**	**$14,384**	

Categories:

1. Items for which the actual prices were significantly less than estimated.
2. Items for which the actual prices were very close to the original estimate.
3. Items for which the scope did not change, but the actual prices were significantly higher than estimated.
4. Items for which the scope did change and the actual unit prices were significantly higher than estimated.
5. Items which were not included in the original estimate.
6. Items which were included in the original estimate, but deleted from the final scope.

TESTIMONY OF
ANTHONY L. LUNARDINI

On Behalf of

HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Campbell Industrial Park CT-1
Cost Basis and Factors Affecting Differences in Cost
Between Original Estimate and Current Forecast to Complete

INTRODUCTION

Q. Please state your name and business address.

A. My name is Anthony Lunardini and my business address is Sargent & Lundy, L.L.C., 55 E. Monroe St., Chicago, IL 60603.

Q. By whom are you employed and in what capacity?

A. I am a Senior Project Manager for Sargent & Lundy, a company based in Chicago, Illinois, with project locations worldwide. As a project manager, I am responsible for the project design, engineering, and management aspects of a project. I am also responsible for planning, tracking, monitoring and managing a project from a cost, procurement, and engineering viewpoint.

Q. Please describe your work experience on power plant related projects.

A. I have more than 35 years of experience in the design and engineering of both fossil and nuclear fueled power stations. My assignments have ranged from structural engineer to project manager for entire plant sites. I have been involved in the design of six combustion turbine projects and numerous studies for other combustion turbine projects. My educational background and experience are provided in HECO-S-17B00.

Q. Please describe your company, Sargent & Lundy.

A. Sargent & Lundy ("S&L") has been in business for more than 100 years. It provides complete consulting, engineering, and project development services for all types of fossil-fuel, nuclear, and renewable power generation and power delivery projects. Our record of accomplishment includes the design of 884 power plants totaling 122,149 MW for clients in the public and private sectors worldwide. We have also designed more than 5,000 circuit miles of high-voltage and extra-high-voltage transmission line and more than 100 substations. Our business focus is exclusively power.

Q. Have you previously submitted testimony in this proceeding?

A. No, I have not.

Q. Have you previously submitted testimony in other proceedings before this Commission or other commissions in other jurisdictions?

A. No, I have not.

Q. What is the scope of your supplemental testimony?

A. My supplemental testimony will discuss the cost estimate for the Campbell Industrial Park Generation Station and Transmission Addition Projects ("CIP CT-1 Projects"). In particular, the cost basis and the factors affecting the differences in cost between the original cost estimate and the current forecast to complete the CIP CT-1 projects.

CIP CT-1 PROJECTS COST ESTIMATING PROCESS

General Basis and Methodology for Order-of-Magnitude Cost Estimating:

Q. Can you describe, in general, how cost estimates for new generating unit projects are prepared, and the factors that could affect the accuracy of the estimate?

A. The first step in the process for preparing cost estimates for new generating unit projects is to prepare a rough order-of-magnitude cost estimate that is subsequently refined as the project progresses and additional project information is developed. A rough order-of-magnitude cost estimate is generally prepared with only a preliminary layout, a summary-level single line diagram, and possibly preliminary flow diagrams for major systems. No equipment is purchased at this time, so no equipment specifications such as: details, sizes, electrical and piping requirements, or foundation requirements are known. Calculations have not yet been performed to size equipment, foundations, steel, or electrical duct runs. Piping, cable, and conduit have not yet been sized or routed. Water and fuel analyses are not generally known at this stage of the project, so final equipment types and sizes cannot be determined.

At this stage of the project, equipment sizes and costs are generally scaled from other projects with similar technology. Quantities for foundations, steel, piping, cable, conduit and raceways, valves, and instruments are based on scaling from other projects with similar technology, or from in-house databases. Labor cost estimates are based on cost estimates or reports for other projects, and average published productivity and labor rate data for a particular geographic region.

Q. What are the key factors which could affect the cost estimates at the rough order-of-magnitude cost estimation stage?

A. As discussed above, at this stage, cost parameters are scaled from other projects with similar technology. Even among projects with similar technology, actual material quantities, equipment costs, and labor hours can vary significantly from project to project, and from region to region. These actual costs will depend on highly variable project-specific factors such as those listed below. None of these factors are generally known at the time of a rough order-of-magnitude cost estimate. These factors include the following:

- Project-specific layouts will significantly affect quantities of piping, cable, conduit, cable tray, and duct banks. Layout issues will also affect the ease or difficulty of construction, thereby affecting construction labor.
- Site-specific criteria such as soil conditions, existing site grading, site

accessibility, existing site infrastructure, existing obstructions, and weather impacts such as wind loading will affect foundation designs and depths, structural designs, amount of civil engineering work and site grading required, and the productivity and hours for construction labor.

- Project-specific criteria such as water quality, fuel analysis, fire and hazard code requirements, redundancy and reliability criteria, available operator and maintenance staffing (and resulting degree of automation and built-in reliability required), and interconnection requirements with the utility grid infrastructure will significantly affect the overall project design, amount of equipment redundancy, equipment sizes, complexity of design criteria, and numbers of valves, instruments, cable, and control system components required. These factors also affect building sizes and design requirements, and in turn, foundation requirements and overall construction labor to install all equipment, systems, buildings, and materials. Equipment costs will vary depending on design and redundancy/reliability requirements as well.
- The cost for a first unit at a particular site (i.e. a "greenfield site") may be more difficult to estimate than the cost for a second unit at an existing site, because less information is known about existing site conditions and infrastructure.
- At the order-of-magnitude cost estimating stage, labor rates are estimated based on established indices, and not on a region-specific labor survey. This was true for the original CIP CT-1 Projects cost estimate. Actual regional labor availability, terms of employment, and

market conditions can have a significant impact on labor costs.

Q. What factors were considered when selecting similar projects to be used as a basis for the CIP CT-1 Projects cost estimate?

A. The factors considered when selecting similar past projects to be used in developing the CIP CT-1 Projects rough order-of-magnitude cost estimate included greenfield site, a "frame" CT (versus an aeroderivative CT), simple cycle configuration intended for peaking operation and a nominal 100MW capacity rating.

Q. What factors affect the construction costs of the project?

A. A rough order-of-magnitude cost estimate is generally prepared before a construction contractor is involved in the project, and therefore without the benefit of construction planning for heavy equipment, a subcontracting plan, or a construction schedule. Heavy equipment rental costs, subcontractor costs, and time spent on construction can significantly affect costs for construction overheads and equipment related to installation. Costs to attract and retain labor in a given market are also not known until the time of construction award.

If there is a time lag between preparation of the initial cost estimate and purchase of equipment and award of construction contract(s), as there was with the CIP CT-1 Projects, market fluctuations may cause significant deviations from originally estimated costs. Market fluctuations that affected power industry costs between 2005 and 2008 are described below.

Q. As the project design progresses, how does this affect the accuracy of the cost estimation?

A. As the project design progresses and design criteria, calculations, and physical layouts of equipment and commodities are established, equipment sizes and quantities can begin to be predicted with more accuracy. However, until equipment is actually purchased, design requirements for foundations and all equipment-interfacing piping, electrical, and control/instrumentation are still not yet known.

Q. How does the actual purchase of equipment help with the accuracy of cost estimation?

A. As equipment contracts are awarded, equipment pricing becomes known with more certainty. There is then a time lag between equipment award and submittal of vendor drawings by the equipment suppliers. These vendor drawings determine foundation sizes, and the size and amount of interfacing piping, instrumentation, valves, cable, conduit, and plant services required to make the purchased equipment operable. Once these interface requirements are known, the designs for foundations, buildings, instrumentation, control systems, piping, cable, duct banks, and conduits can be completed. After designs are completed, material costs and construction labor can be estimated with greater accuracy.

Market Factors Affecting Power Industry Costs Between 2005 and 2008:

Q. Please describe the market factors that affected power industry costs between the years 2005 to 2008.

A. During the period between 2005 and 2008, there were a number of unusual market conditions that resulted in material and construction labor cost escalations beyond the normally expected annual price escalation. Some of these conditions are summarized below:

1) Major reconstruction and rebuilding programs following major hurricanes such as Katrina in August 2005 in the southern U.S. mainland significantly increased the demands on the national labor pool. New power plant

construction to meet national need for increased power generation combined with increased construction of major air quality control projects for solid fuel plants further increased the demands on the national labor pool. The contractors' need to attract and retain labor caused labor costs to escalate to account for items such as work-week incentives, additional per diem, and completion bonuses, in addition to the normal 4 to 6% expected annual craft labor escalation costs. These types of non-labor rate escalations are not typically captured in industry indices, as they vary with market conditions. S&L tracks these factors primarily by communicating with construction contractors on ongoing projects. The productivity of labor was affected by these market conditions as well. The original cost estimate included an allowance for regional productivity based on extrapolation from Sargent & Lundy's database; however, any productivity assumptions at the time would have been based on historical experience and did not include or foresee any of the additional impacts of the market conditions that occurred between 2005 and 2008. The original cost estimate included a productivity factor of 1.10 compared to Houston-area productivity (i.e. 10% more labor hours per task). Please note that any productivity impacts of longer work weeks would be in addition to the 1.10 factor used in the original cost estimate. Recent data published by Compass International that was not available at the time the original cost estimate was developed includes a productivity factor of 1.30 for Hawaii. Any productivity impacts of longer work weeks would be in addition to the 1.30 factor.

2) By the third quarter of 2006, concerns about the availability of labor into the future caused many major construction contractors, who had previously

been willing to competitively bid projects on a firm price basis, to refuse to provide firm price proposals for labor costs, and instead submit cost proposals based on a time-and-material approach. This was done by the contractors to eliminate the price risk of fixed price proposals. The large number of construction opportunities from 2006 into 2008 allowed the construction contractors to take this approach. In addition, the large number of construction opportunities allowed the contractors to be selective about opportunities they pursued, and to turn down opportunities. That is, in some cases, the construction contractors were declining to submit bids in response to requests for bids. Many power industry owners were agreeing to contract terms in order to lock in a contractor, and secure the construction labor that they needed during a given time frame.

3) Indirect costs for a construction project are generally estimated as a percentage of the overall construction cost, with the percentage value determined by market conditions. When the overall construction costs increase, indirect costs will increase proportionately. In addition, contractors will often increase the percentage of the project cost that they include for indirects in a busy market, as a means of covering some of the risk they take on when skilled resources are at a premium.

4) Strong demand and stagnant supplies for commodities in the global market, as well as the U.S., drove prices to all-time highs in 2008. Material prices began escalating at higher than expected rates in late 2005, and continued on a steady rapid climb through mid-2008, based on indices such as Bureau of Labor Statistics, Handy-Whitman, and Engineering News Record. Approximate examples of commodity price increases include the following:

- Structural steel cost indices rose by 67% between April 2005 and August 2008. Between August and December 2008, steel prices fell, but were still 20% higher than 2005 values. In addition, decreases in retail costs of fabricated steel components tend to lag decreases in raw materials by three to six months, due to backlogged materials, and most of the steel-based materials were purchased for the CIP CT-1 Projects before prices began to decrease.
- Piping cost indices rose 43% between April 2005 and August 2008. Between August and December 2008, piping cost indices fell, but were still 32% above 2005 levels.
- Transformer and large electrical equipment cost indices rose by 49% between April 2005 and December 2008.
- Electrical cable costs more than doubled during this time period, based on the steep rise of copper prices.
- Storage tank cost indices rose 13% between April 2005 and December 2008.
- The Engineering News Record (ENR) building cost index rose 15% between April 2005 and August 2008, and the ENR construction cost index rose 16% during this same period. These indices rose at a slower rate than others, because they are more heavily weighted toward commercial (rather than heavy industrial) labor and materials, such as wallboard and wood materials, carpenters, laborers, etc.
- Ancillary equipment costs in some market segments rose from 50% to 80% over the time period, affecting the overall power market.
- Concrete prices continue to rise nationally, despite the overall

economic downturn, due to limitations in national supply capacity.

- Market factors may have been further magnified for Hawaii, with rapidly escalating fuel costs increasing shipping costs for equipment and materials, and with a more limited range of contractors and suppliers available.

Q. How do these factors affect other clients of Sargent & Lundy during this same period?

A. Other S&L clients with new power plant or major environmental retrofit projects experienced similar increases to those experienced by Hawaiian Electric during this same time period.

Basis for the Original Campbell Industrial Park Cost Estimate

Q. Please explain the basis for the original estimate for the combustion turbine installation labor for the CIP CT-1 Projects.

A. The original combustion turbine installation labor cost estimate was based on past labor hour estimates for projects in a similar size range, and were initially prepared before the combustion turbine supplier was selected. Because the U.S. installation experience is much greater for General Electric ("GE") turbines than for Siemens combustion turbines, estimates were scaled from other estimates primarily for GE equipment.

Q. How does the basis for the actual combustion turbine installation labor cost differ from the basis used in the original cost estimate?

A. The current turbine installation labor costs are based on a full accounting of all actual equipment, a full understanding of ancillary components furnished by the turbine supplier, a final arrangement of the combustion turbine/generator plant that includes a raised inlet filter, and a finalized construction sequence and schedule that includes an accurate accounting of heavy equipment and indirects. Actual labor costs are also based on the actual market conditions noted above.

Q. Please explain the basis for the original estimate for foundation quantities for the CIP CT-1 Projects, and why was the actual cost for the foundations higher than originally estimated?

A. The original estimates for foundations were scaled from other projects, again, with the majority of U.S. experience being GE machines. As noted above, site-specific and equipment-specific factors can have a very significant impact on foundation costs. The Siemens equipment required a significantly larger foundation than previous GE projects, due to a significantly more stringent vibration requirement. This requirement was established after vendor drawings were received. The establishment of site-specific design criteria such as stack requirements further increased foundation quantities. Foundation requirements for the buildings were further refined after the building design was developed and resulted in larger foundations than assumed in the rough order-of-magnitude cost estimates. Increases in the drain systems were identified after the water treatment system was defined which further increased foundation quantities. Foundation quantity requirements for the tanks and water treatment equipment were also determined to be higher than estimated after these components were purchased and vendor drawings were received.

Q. Please explain some of the factors that can affect the cost estimates for civil engineering/sitework.

A. As discussed previously, costs for civil engineering and sitework are highly variable and site-dependent, and difficult to estimate with accuracy before site criteria are developed. In regards to the CIP CT-1 Projects, the civil engineering work cost estimates were prepared before the berm work was designed, and before detailed design for the rest of the site was developed. As the design was developed, parts of the site were found to be too narrow for the assumed berm design, so a 2,000 linear foot concrete wall was added in lieu of earthwork, at a significantly higher cost.

Q. Please explain the basis for the original estimate for electrical duct banks for the CIP CT-1 Projects, and why the actual cost for the electrical duct bank was higher than estimated?

A. The electrical duct bank quantities in the original estimate were based on numbers scaled from other similar projects in Sargent & Lundy's database. However, as discussed previously in my testimony, the actual quantities can vary significantly from the assumed quantities based on the actual site layout, electrical design criteria, and contractor input. The actual electrical duct bank quantities for the CIP CT-1 Projects were higher than originally estimated, due to requirements determined by the layout and design criteria. Requirements for duct banks to serve the administration/control building, the closed cooling water heat exchanger, and other equipment across the site were developed after the layout and equipment requirements were finalized.

Q. Please explain the basis for the original estimate for cable quantities for the CIP CT-1 Projects and why there was a different with the actual quantities that were required.

A. The original electrical cable quantities were based on a typical simple cycle combustion turbine project. However, the CIP CT-1 Projects require a higher degree of redundancy and automation than other simple cycle projects, in order to accommodate reliability requirements due to its island location, remote operation requirements, black start capability, and the requirement for three separate sources of water. All of these design criteria were finalized during the detailed engineering phase and contributed to the additional reliability and redundancy requirements of this unit compared to others in the industry.

Q. Please explain the basis for the original estimate for piping quantities for the CIP CT-1 Projects and compare it with the actual quantities that were required.

A. Piping quantities were originally estimated based on preliminary flow diagrams, which defined piping requirements for major systems. Because the piping preliminary design was slightly further along when the original estimates were prepared than other commodities, the piping quantities in the original estimate were closer to the actual quantities than other types of commodities.

Q. Please describe the refinements to the design criteria elements that affected the cost estimate for the CIP CT-1 Projects.

A. The following design criteria elements were defined significantly later than the 2005 cost estimate, after the design was further developed. Each of these had an impact on the actual quantities and costs of the project:

- The degree of redundancy, reliability, and automation required, due to its island location, remote start/stop operation requirements, black start capability, and the requirement for three separate sources of water, as described above. These requirements affected costs for equipment, cable, conduit and cable tray, duct banks, valves, instrumentation and controls, and overall labor to install all of these requirements. These requirements also affected the size and layout of plant buildings to accommodate all requirements.

- Definition of water treatment system requirements after the rough order-of-magnitude cost estimate, and the requirement that three separate sources of water be treated and accommodated. After the original estimate was completed, Hawaiian Electric chose to have the system designed to treat reclaimed water and potable water, in addition to groundwater, to maximize the reliability and flexibility of the unit. These requirements affected water treatment building and foundation costs, cable and conduit/raceway quantities, valve and instrument costs, and labor to install all of these requirements.
- Definition of black start and remote start criteria after the original estimate. These requirements affected foundation costs, cable and conduit/raceway quantities, valve and instrument costs, control system costs, and labor to install all of these requirements.
- Definition of design criteria such as foundation criteria (which affected foundation quantities and costs) and the results of the process hazards analysis (which was conducted in 2008 and affected valve and electrical costs), and the labor to install these requirements.
- The requirement for flexibility of operation to use water tanks interchangeably for raw water or finished water storage became clear as the design developed. This requirement affected quantities for piping, valves, electrical and control services, and the labor to install.
- Purchase of equipment, which defined foundation, piping interface, and electrical interface requirements, and labor to install.

Q. Please describe the evolution of the project design, even after the installation contractor was selected.

A. The evolution of the design after the installation contractor was selected included:

- Hawaiian Dredging Construction Company, Inc. ("HDCC") was selected based on preliminary target pricing, which in turn was based on preliminary design information.
- Design drawings and details were completed after initial contractor selection. The current labor cost forecasts reflect the scope of the final design, which in turn reflects the higher quantities described earlier in my testimony.
- The open book- target pricing model was established due to schedule requirements and construction market conditions. The open book model allowed Hawaiian Electric the opportunity to secure a contractor during a busy market time, before the design could be completed sufficient for firm price bidding. Early involvement of the contractor benefited the project in terms of construction planning, and final pricing is now based on the finalized design.

CURRENT FORECAST TO COMPLETE CIP CT-1 PROJECTS

Q. What is the current cost estimate to complete the CIP CT-1 Projects?

A. The current cost estimate to complete the CIP CT1 Projects is $193,100,000. The detailed breakdown for this cost estimate is provided in Mr. Isler's testimony, HECO ST-17A.

SUMMARY

Q. Please summarize your testimony.

A. The original cost estimate for the CIP CT1 Projects was developed using cost and scope information from past similar projects coupled with assumptions on the layout, design scope and schedule for the CIP CT-1 Projects and assumptions on the forecasted escalation factors to account for material, equipment and construction cost increases. However, from 2005 to 2008, global and national events in combination produced unexpected and significant increases in the costs for commodities, equipment and construction that also impacted costs in Hawaii. Also, as the design engineering for the project progressed, there were significant increases in the scope of work required to meet the design requirements for the CIP CT-1 Projects. The current project scope is significantly greater than assumed in the original cost estimate. In short, higher costs for commodities, equipment and construction labor combined with the increases in scope for the project have increased project costs compared to the original cost estimate. Other S&L clients with new power plant or major environmental retrofit projects experienced similar increases to those experienced by Hawaiian Electric during this same time period.

Q. Does this conclude your testimony?

A. Yes, it does.

ANTHONY L. LUNARDINI
Project Manager
Fossil Power Technologies

Sargent & Lundy LLC

EDUCATION

University of Illinois at Chicago - B.S. Structural Design - 1974

REGISTRATIONS

Structural Engineer - Illinois

Professional Engineer – Maine, New Jersey, Texas

EXPERTISE

Project Management
Plant modifications for fossil power projects
New generation fossil power projects
New generation technology screening
New generation siting studies
Structural engineering
General building criteria

RESPONSIBILITIES

Mr. Lunardini is responsible for the project management, design, and engineering aspects of projects. He is responsible for planning, tracking, monitoring and managing the project from a cost, procurement, and engineering viewpoint. He provides guidance and supervision to engineers and designers, monitoring their work for conformance with Sargent & Lundy's design standards.

EXPERIENCE

Mr. Lunardini has more than 35 years of experience in the design and engineering of both fossil- and nuclear-fueled power stations. His assignments have ranged from structural design engineer to project manager for entire plant sites. His responsibilities have included the design of reinforced concrete and structural steel framing, turbine foundations, building foundations, and boiler structures. Mr. Lunardini has prepared design criteria and has been involved in preliminary layout and project scheduling for both fossil- and nuclear-fueled power plants.

Mr. Lunardini as a Project Manager since 1995 monitors, supervises and coordinates power plant projects including conceptual design, and detail design and site studies. He interfaces with several disciplines including mechanical, electrical, civil/structural, I&C, scientists, environmental engineers, ecologists, and economists and manages their day to day activities.

Mr. Lunardini is currently the Project Manager for the Hawaiian Electric Company Campbell Industrial Park simple cycle project and the Dorad 800MW Combined Cycle Plant.

Mr. Lunardini was Project Manager for the San Juan Environmental Project, which included the addition of Low NOx burners, baghouses, and Mercury removal technology to 4 units that have a total capacity 1800 MW.

ANTHONY L. LUNARDINI
Project Manager
Fossil Power Technologies

Sargent & Lundy LLC

Mr. Lunardini has managed the Amp- Ohio Baseload Generation Project which started as a Generation Technology Screening Study to best fit the clients desire to own their own assets with the proper fit of generation technologies. The next phase of the work included development of the site requirements for the candidate technology and to perform a regional site screening study. Individual sites were then located and were evaluated. The conceptual model was then adapted to the short listed sites and more detailed performance, economic and intangible criteria were developed. Permit applications were prepared a two unit 960 MW coal plant on a greenfield site with all major permit applications being coordinated by Mr. Lunardini.

Mr. Lunardini was also the Project Manager for the New Ulm Generation Supply Study, which includes technology screening, site feasibility and generation resource planning for their existing and future facilities. Mr. Lunardini has worked closely with the conceptual design and technology-screening group to produce standard plant models for Excelon to use for future planning.

Mr. Lunardini was previously the project manager for the Corpus Christi Energy Center at the CITGO Refinery. This EPC project is a 500-MW combined cycle cogeneration project in a joint venture with Zachry Construction. He was also involved in the Exxon Chemical Company Baytown Cogeneration Project and the Shell Oil Company Deer Park Cogeneration Project.

Mr. Lunardini's other assignments have included managing the Engineering Software Development and Implementation Group's work on all of Sargent & Lundy's new unit design and services projects. This work includes directing the development of all Sargent & Lundy engineering software programs. This also includes assisting the project teams in the implementation of Sargent & Lundy's PLADES Plant Design and Management System.

Other projects include providing support for Kentucky Utilities Company's Ghent 1 FGD retrofit project, which involves detailed design of various FGD-related systems. He also served as the structural supervisor for the circulating fluidized bed design project at Nova Scotia Power Corporation's Point Aconi plant. He was responsible for all the structural design work for the power block, which included interfacing structural elements with the circulating fluidized bed boiler and the fabric filter. He has also participated in various ductwork and precipitator walk downs and the associated recommended repairs.

Mr. Lunardini was involved with the preliminary design of the Illinois Low-Level Radwaste Storage Facility and coordinated the structural design of the vaults and support structures. He has also completed master site plans for seven nuclear plants to upgrade their facilities. This effort has involved the review of the existing master plan, interview of users, preparation of a new master plan, and new building program reports.

Mr. Lunardini was also assigned as a structural field coordinator at a nuclear power plant under construction, where his responsibilities included coordination of the design activities of Structural Department personnel at the site and interface with contractor and client personnel in order to resolve field problems. The structural site staff under his supervision reached a peak manpower of 205 engineers and 30 draftsmen. Under Mr. Lunardini's supervision the site activities developed from being a liaison and walkdown group to providing expedited design output documents and performing the calculation backup for the design basis requirements. After fuel load, the site staff began preparing complete plant modification packages to be installed by the station operating and maintenance personnel, which included an impact review of system revisions per 10 CFR 50.59.

Before joining Sargent & Lundy in 1974, Mr. Lunardini worked for two years as a civil planning engineer for the H. K. Ferguson Company.

His specific experience includes:

PLANT DESIGN

- **Dorad 800MW Combined Cycle Plant (Dual Fuel)**

  Project Manager (2009 to Present)

- **Public Service Company of New Mexico**
  - San Juan Environmental Project, Coal, 1800 MW for 4 units

    Implemented consent decree requirements including baghouse additions, mercury removal, neural net, and low NOx burner conversion.

    Project Manager (2005 to Present)

- **Hawaiian Electric Company**
  - Campbell Industrial Park Simple Cycle, oil, 120 MW

    Combustion turbine installation detailed design and permitting assistance.

    Project Manager (2004 to present)

- **FPL Energy**
  - Rhode Island Energy Center, natural gas, 500 MW, combustion turbine/ combined cycle

    Inlet heating coils and various plant modifications

    Project Manager (2004 to 2005)

ANTHONY L. LUNARDINI
Project Manager
Fossil Power Technologies

Sargent & Lundy LLC

- **SkyGen / Calpine Energy**
  - Corpus Christi Energy Center, natural gas, 500 MW, combustion turbines/combined cycle.

    Project Manager. (2000 to 2003)

- **Exxon Chemical Company**
  - Baytown Cogeneration Expansion Project, 80 MW, combustion turbine.

    PLADES Coordinator. Refinery design and construction. (1995 to 1997)

- **Shell Oil Company/Houston Industries Energy**
  - Deer Park, natural gas and refinery gas, 140 MW, combustion turbine.

    Engineering Manager. Manufacturing complex cogeneration project. Design construction. (1993 to 1995)

- **Mitsui & Co. (U.S.A.)**
  - Point Aconi, coal, 165 MW.

    Fluidized bed boiler.

    Structural Project Engineer. Supervised all power block design work. (1989 to 1992)

- **Gulf States Utilities Company**
  - Nelson 6, coal, 615 MW.

    Supervising Design Engineer. Participated in ductwork walkdowns, repair, and design. (1987 to 1988)

- **Omaha Public Power District**
  - Fort Calhoun, nuclear, 502 MW.

    Senior Structural Engineer. Block wall analysis and as-built reconciliation. (1987 to 1988)

- **TU Electric**
  - Big Brown 1 and 2, lignite, 593 MW each.

    Senior Structural Engineer. Supervised structural design of ash silo and dewatering bin complex. (1987 to 1988)

ANTHONY L. LUNARDINI
Project Manager
Fossil Power Technologies

Sargent & Lundy LLC

- **Commonwealth Edison Company**
  - Braidwood 1 and 2, nuclear, 1175 MW each.

    Structural Field Coordinator. Supervised all structural design work, such as as-built reconciliation walkdowns, modification packages, construction verification programs, and final loud check analysis. (1983 to 1987)

- **Wisconsin Power & Light Company**
  - Edgewater 4 and 5, coal, 751 MW total.

    Senior Structural Engineer. Supervised ductwork and precipitator support steel design. (1983)

- **Northern Indiana Public Service Company**
  - Schahfer 17 and 18, coal, 393 MW each.

    Senior Structural Engineer. Supervised all boiler room, turbine room, and coal handling structural design. (1979 to 1983)

  - Bailly N-1, nuclear, 684 MW (cancelled).

    Senior Structural Engineer. Supervised concrete framing and pile foundation for turbine building. (1977 to 1979)

- **The Cincinnati Gas & Electric Company**
  - Miami Fort 8, coal, 558 MW.

    Structural Engineer. Designed duct support steel, boiler room steel, and miscellaneous equipment foundations. (1975 to 1977)

- **Interstate Power Company**
  - Lansing 4, coal, 275 MW.

    Structural Engineer. Designed concrete turbine foundation. (1974 to 1975)

- **The Detroit Edison Company**
  - Fermi 2, nuclear, 1203 MW.

    Structural Engineer. Designed concrete framing in the residual heat removal building and equipment foundations. (1974)

FLUE GAS DESULFURIZATION

- **Kentucky Utilities Company**
  - Ghent 1, coal, 550 MW.

    FGD retrofit project, including detailed design of FGD-related systems. (1991)

STORAGE FACILITIES AND INDUSTRIAL DESIGN

- **Westinghouse and Illinois Department of Nuclear Safety**
  - Illinois Low-Level Radwaste Storage Facility.

    Supervising Design Engineer/Structural Project Engineer. Preliminary design of storage vaults and all processing administration, and maintenance structures. (1989)

STUDIES

- **Hawaii Electric Light Company**
  - Generation Asset Management Condition Assessment Study (2005)
    - Shipman
    - Hill
    - Puna
    - Kanoelehua
    - Waimea
    - Keahole

- **New Ulm Public Utilities Commission**
  - Various Fuels

    Siting and resource planning for new generation.

    Project Manager (2006)

- **American Municipal Power-Ohio, Inc. (AMP-Ohio)**
  - Coal, 980 MW.

    Base load generating facility study; including siting, technology screening, fuel study and major permit application coordination.

    Project Manager (2003 to Present)

- **Exelon**
  - Technology analyses for new generation options. (2003 to 2004)

- **Public Service Electric and Gas Company**
  - Hope Creek 1, nuclear, 1117 MW;
  - Salem 1 and 2, nuclear, 2298 MW total.

    Reviewed existing master plan, interviewed users, and prepared new master site plan and one new building program report using a nuclear engineering perspective. (1989)
- **Commonwealth Edison Company**
  - LaSalle 1 and 2, nuclear, 1132 MW each.

    Supervising Design Engineer/Structural Project Engineer. Conceptual development of warehouses, training building, office building, and access facility. (1987 to 1989)
  - All six nuclear sites.

    Supervising Design Engineer/Structural Project Engineer. Developed the site layout and usage plan study for each site. Interviewed stations, operations, and management for input. (1988)

MEMBERSHIP

Structural Engineers Association of Illinois

PUBLICATION

"Nuclear Stations' Facilities Improvement Planning," Sargent & Lundy General Engineering Conference, Chicago, Illinois, Spring 1989

SUPPLEMENTAL TESTIMONY OF
BRENNER MUNGER

MANAGER
POWER SUPPLY ENGINEERING DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Cost Variance Explanations for Power Supply Capital Expenditure Applications

INTRODUCTION

Q. Please state your name and business address.

A. My name is Brenner Munger and my business address is 820 Ward Avenue, Honolulu, Hawaii 96814.

Q. By whom are you employed and in what capacity?

A. I am the Manager of the Power Supply Engineering Department for Hawaiian Electric Company, Inc. ("Hawaiian Electric" or "Company"). My educational background and experience are provided in HECO-ST-17C00.

Q. What is the scope of your testimony?

A. My testimony will explain the cost variances for Power Supply-related capital expenditure applications that were placed into service in 2008 and 2009.

POWER SUPPLY ENGINEERING CAPITAL EXPENDITURE APPLICATIONS

Q. Were there Power Supply Engineering related projects with 2008 and 2009 service dates for which capital expenditures applications were submitted pursuant to General Order No. 7 paragraph 2.3(g)(2), as modified by Decision and Order No. 21002, filed May 27, 2004, in Docket No. 03-0247?

A. Yes. In HECO-1704, Hawaiian Electric identified two Power Supply Engineering related projects that were placed in service in 2008 and 2009. Those projects are:

1) Community Benefits Package (Docket No. 05-0146), and
2) Barbers Point Fuel Oil Tank #131 Renovation project (Docket No. 2007-0409), which was completed in March 2009.

Community Benefits Package

Q. Please describe the capital projects that were included in the Community Benefits Package relating to the Campbell Industrial Park ("CIP") Generating Station and Transmission Additions project.

A. The capital projects included in the Community Benefits Package consisted of (1) construction of water facilities to substitute reverse osmosis water ("RO Water") from the Board of Water Supply's Honouliuli Wastewater Treatment Plant for potable water presently being used for industrial purposes at Hawaiian Electric's Kahe Power Plant, and (2) the installation of three air monitoring stations. Hawaiian Electric requested that the costs for the capital projects included in the Community Benefits Package be recoverable as part of the cost of the CIP Generating Station Project, except that the costs relating to the repair and maintenance of the proposed RO water pipeline project will be handled by the Board of Water Supply.

Q. What were the estimated costs for the capital projects included in the Community Benefits Package?

A. The estimated cost of the RO Water pipeline was approximately $7.4 million. A section of the RO Water pipeline will be dedicated to the BWS, and special accounting and ratemaking treatments, as agreed to by Hawaiian Electric and the Consumer Advocate, and as approved by the Commission, will be applied to the RO Water pipeline. Additional details regarding the accounting and ratemaking treatments are provided in Docket No. 05-0146.

The estimated cost of the air quality monitoring stations was approximately $570,000.

Q. Did the Commission approve the expenditure of capital for the Community Benefits Package?

A. Yes. In Decision and Order No. 23514, filed June 27, 2007, in Docket No. 05-0146, the Commission approved the commitment of funds for the RO Water pipeline and the Environmental Monitoring Programs.

Q. How was the project work scope for the RO Water pipeline determined for the Application cost estimate?

A. At the time the application cost estimate was developed, a "high-level" conceptual work scope was developed based on the known pipeline route, the pipeline length and the water demand at the Kahe Power Plant. The construction scope included both "open trenching" and Horizontal Directional Drilling (HDD) construction methods, based on knowledge gained from the Waiau Fuel Oil Pipeline project constructed in the same area and completed in 2004.

Q. How was the original cost estimate developed?

A. The cost estimate for the RO Water Pipeline project in the application submitted on June 17, 2005, was developed using cost information from the Waiau Fuel Oil Pipeline project. Using the historical cost information from this similar project as the basis, the cost estimate for the RO Water Pipeline project was developed by scaling the costs relative to the pipeline length, the different size and type of pipe, and an estimate of open trenching and HDD construction. Pipeline vendors and construction contractors were also contacted for current information on pipeline material costs and construction unit costs.

Q. What is the current cost estimate for this project?

A. The current cost estimate for this project is $7,423,300.

Q. How much does this cost vary from the PUC approved amount?

A. The project cost is forecasted to meet the PUC approved amount.

Q. What are the total capital expenditures of this project to date?

A. As of June 30, 2009, the total capital expenditures of this project were $4,933,211. The remaining project costs are identified and total project cost is expected to be within the original PUC cost estimate

Q. What is the accuracy of this cost estimate?

A. The accuracy of this cost estimate is high. We are very close to completing the project. The majority of the construction work was completed in June 2009. The balance of the project work is primarily inside the Kahe Power Plant property and is expected to be completed by July 31, 2009. The scope of the remaining work is well defined and is proceeding as planned. We do not expect to incur any cost increases. The contractor is on a fixed fee contract for the work and the pending invoice amounts are known

Q. What actions were taken to manage the project cost?

A. Early in the project planning phase, discussions and negotiations were held with the contractor that performed the construction work for the Waiau Fuel Oil Pipeline project and other pipeline work in the State Railroad right-of-way. This contractor's experience, demonstrated capabilities, and working relationships with the State DOT and land owners near the RO Water Pipeline route enabled us to develop a good project scope and good project cost estimate early in the project cycle. This contractor also provided valuable input on constructability during the final design phase of the project. Through these close working arrangements during the planning and design phase, the project has progressed on schedule, on budget and with no change orders to date.

Q. What is the current status of the project?

A. The project is in the final stages of construction. The project is expected to be in use by July 31, 2009.

Q. What is the scope of the Air Quality Monitoring Program?

A. The Air Quality Monitoring Program involves the construction and installation of three air quality monitoring stations ("AQMS") in the general vicinity of Hawaiian Electric's Campbell Industrial Park ("CIP") Generating Station. Each AQMS will continuously monitor ambient air quality in the area. The AQMSs will be configured to measure several air pollutants including nitrogen dioxide, sulfur dioxide, carbon monoxide, ozone, and particulate matter.

Q. Where are the AQMS located?

A. There are three stations on the Waianae coast located in Waianae, Lualualei and Timberline. The Waianae Station is located in Waianae Valley along Waianae Valley Road. The Lualualei Station is located at the Nanakuli Civil Defense site. The Timberline site is located in the mountains above Makakilo.

Q. How was the project work scope determined for the Application cost estimate?

A. Beginning in the summer of 2004, Hawaiian Electric began discussing plans for the new CIP CT-1 generating unit with neighboring communities. Meetings with individuals and various community and business groups focused on describing the energy situation on Oahu and what it would take to meet Oahu's energy needs. These meetings also provided an opportunity for the community advocates and leaders to provide input about what community benefits were most important and appropriate for the affected communities. As a result of these community meetings and dialogue and filings with the Public Utilities Commission, a set of Community Benefits was approved. One of the benefits was the installation of the three AQM stations along the Waianae Coast.

Q. What is the current capital cost estimate for this project?

A. The current capital cost estimate for this project is $957,000, which is approximately $387,000 or 68% more than the Application cost estimate.

Q. How was the original cost estimate developed?

A. The original cost estimate was developed based on actual costs from past AQM installations.

Q. What are the reasons for the cost variance?

A. The higher actual cost is primarily due to the inadvertent omission of Hawaiian Electric labor and associated overheads and AFUDC. This accounts for $250,000 of the cost variance. Higher than estimated material costs and outside services contributed to $137,000 to the cost variance. The Company labor for the project covers project management, working with the community, site selection/acquisition, permitting, engineering, materials procurement, equipment testing and installation work.

Q. What actions did the Company take to manage the project cost?

A. The procurement of three AQM stations was initiated using a competitive bid process. However, based on the proposals received, the cost for each AQM station was higher than the estimate (as was stated in Docket No. 05-0146) by about 26%. To manage project costs, it was decided to purchase only two new AQM stations and to refurbish an existing AQM station which became available in December 2007 when the Department of Health approved the shut down of an existing AQM station on Maui. The refurbishment alternative for the third AQM station resulted in an overall savings of approximately $94,000 for the project.

Q. What is the current status of the project?

A. The project was placed in-service in August 2008. All three AQM stations have been sited, connected and are reporting data. An Interim Accounting Report for the air quality monitoring stations was filed on October 8, 2008 and is hereby incorporated by reference. A Final Cost Report for the project will be filed once all of the outstanding charges have been reconciled.

Barbers Point Tank #131 Renovation

Q. Please describe the Barbers Point Fuel Oil Tank 131 Renovation project.

A. The Barbers Point Tank Farm ("BPTF") Tank 131 is one of three identical low sulfur fuel oil ("LSFO") tanks located at the Hawaiian Electric Barbers Point Tank Farm in the Campbell Industrial Park. These are the largest fuel oil storage tanks in the Company's system. These tanks receive LSFO deliveries from Chevron and Tesoro and are used to transfer LSFO to Hawaiian Electric's Kahe and Waiau Power Plants. Tank 131 was inspected in 2007 and the floor was found to have significant corrosion that required replacement in order to ensure safe service. The tank was retrofitted with an El Segundo-type bottom, which consists of a new steel floor and concrete barrier laid over the original steel floor. The El Segundo bottom utilizes an impermeable liner that will effectively contain leaks. The new bottom was installed to prolong the useful life of Tank 131 by thirty years. The estimated cost of the project was approximately $4.1 million.

Q. How was the project work scope determined for the Application cost estimate?

A. A third party tank inspection was performed in accordance with American Petroleum Institute (API) 653 guidelines in 2007. The inspection report noted significant tank floor and shell corrosion, degradation of tank appurtenances, high risk for leaks, and recommended tank renovation before returning the tank to service. Hawaiian Electric has completed numerous similar tank renovation projects and is familiar with the efforts required to successfully complete this type of tank renovation. The API 653 report issued for BPTF Tank 131 and experience with historical tank renovation projects assisted in providing a defined work scope, including renovation to the tank floor, shell, and other necessary appurtenances.

Q. How was the Application cost estimate determined?

A. The scope of work for this project, i.e., retrofitting a fuel oil tank with an El Segundo bottom, was similar to previous projects at Hawaiian Electric. The majority of the scope was estimated utilizing updated contractors' estimates. Costs for remaining work and Hawaiian Electric labor activities were estimated based on previous similar jobs. Third-party engineering consultants reviewed the contractors' estimates for reasonableness prior to submission of the Application.

Q. Did the Commission approve the expenditure of capital for the Tank #131 Renovation project?

A. Yes. In Decision and Order No. 24228, filed May 15, 2008, as clarified by Order Granting Clarification of Decision and Order No. 24228, filed June 10, 2008, the Commission approved the Application for the Tank 131 project.

Q. What is the current status of the project?

A. Project construction was completed in March 2009 and the tank has been returned to service. An Interim Accounting Report for the Tank #131 Renovation project was filed on April 21, 2009, and is hereby incorporated by reference. A Final Cost Report will be filed once all of the outstanding charges have been reconciled.

Q. What is the current cost estimate for this project?

A. The current cost estimate for this project is $4,074,351.

Q. How much does this cost vary from the PUC approved amount?

A. The forecasted project cost variance is less than one percent of the PUC approved amount.

Q. What is the accuracy of the forecasted cost estimate?

A. The accuracy of this cost estimate is high. As of June 30, 2009, the actual cost booked to this project was $3,230,347. The remaining expenses are defined contractor milestone payments for completed work. The invoices have been received by Hawaiian Electric and the costs will be recorded against the project when the invoices are paid.

Q. How did Hawaiian Electric manage project costs for the Tank #131 Renovation project?

A. The project started with a well defined work scope based on a thorough interior inspection of the tank. Hawaiian Electric has retrofitted fuel storage tanks with El Segundo bottoms in the past, and has good familiarity with the efforts needed to successfully complete this type of tank modification. Per American Petroleum Institute Standard 653, fuel storage tank renovations must be performed by contractors who are certified by the American Petroleum Institute (API). An API-certified contractor was already mobilized on Oahu, doing work for another customer in Campbell Industrial Park. Hawaiian Electric obtained firm pricing for the renovation of BPTF Tank 131 from this contractor based on the defined project scope. After conferring with third-party engineering consultants, Hawaiian Electric determined the costs to be reasonable. Throughout the project, engineers and inspectors monitored the contractor's work execution, schedule progress, quality control, safety practices, and conformance to specification requirements.

Q. Does this conclude your testimony?

A. Yes, it does.

SUPPLEMENTAL TESTIMONY OF KEN T. MORIKAMI

MANAGER
ENGINEERING DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Cost Estimating for Energy Delivery Projects; Cost Variance Explanations for Energy Delivery Capital Expenditure Applications

INTRODUCTION

Q. Please state your name and business address.

A. My name is Ken Morikami and my business address is 820 Ward Avenue, Honolulu, Hawaii 96814.

Q. By whom are you employed and in what capacity?

A. I am the Manager of the Engineering Department in the Energy Delivery Process Area for Hawaiian Electric Company, Inc. ("Hawaiian Electric" or "Company"). My educational background and experience are provided in HECO-ST-17D00.

Q. What is the scope of your testimony?

A. My testimony will: (1) describe the method by which the Engineering Department in the Energy Delivery Process area develops cost estimates for its projects, and (2) explain the cost variances for Energy Delivery-related capital expenditure application projects that were placed into service in 2008 or 2009.

ENGINEERING DEPARTMENT PROJECT COST ESTIMATING

Q. How does the Engineering Department in the Energy Delivery Process Area at Hawaiian Electric develop costs estimates for its projects?

A. The cost estimating process follows these basic steps: (1) identify scope of work, (2) identify deliverables, (3) identify risks, and (4) create schedule and cost estimate. Additional information regarding these steps is provided in the following paragraphs.

Identify Scope of Work

Upon receipt of a request, whether it is an internal Hawaiian Electric customer or an external customer, the project engineer communicates with that customer to identify the scope of work involved to address the request.

Identify Deliverables

The project engineer develops a list of deliverables to address the scope of work and also identifies the activities to complete each deliverable. Typical deliverables include: proposal letters, material requisitions, design drawings, construction packages, contracts, permits, and construction schedules.

Identify Risks

The project engineer develops a list of risks which could affect the project's scope or schedule, analyzes the cause and effect of each risk, and plans a response to each risk. The project engineer identifies the activities to complete each response plan. Some of the risks that the project engineer encounters are: limited working hours due to Hawaiian Electric's system operational reasons or roadway work constraints, insufficient labor resources, delays in obtaining permits, delays in obtaining easements, changes in core material costs, past history on outside customers' project schedules, and poor weather.

Create Schedule and Cost Estimate

The project engineer creates a duration and cost estimate for each activity which has been identified. The cost estimate is developed using an estimating program which applies standard labor hours to the various construction activities and provides consistent estimates between the projects. Other resources used in the cost estimation process are: actual costs from similar past projects, industry standards, consultant's data, equipment manufacturers' information, personal experience, and professional networks and affiliations. The project engineer then develops a project forecast and cost budget based on the duration and cost estimates for each activity. Throughout the various phases of a project (planning, design, permitting, material purchase, and construction), the project engineer continues to adjust the cost estimate.

Q. Why do project cost estimates change in the Energy Delivery Process Area?

A. A project's cost estimate is created for budget approval but the project engineer still must typically perform the following tasks in order to complete the project: (1) Field Inspections, (2) Land Survey, (3) Material Cost/Procurement, (4) Permits, (5) Contractor Bids, and (6) Government Policies. The project may also encounter (7) Revised Customer Requests. Each of these tasks may identify changes to the scope of work and schedule of the project. The changes from these tasks may lead to increases or decreases in the cost estimate.

Q. How do these tasks affect the project's cost estimate?

A. <u>Field Inspections</u>

Detailed field inspections allow the project engineer to gather engineering data to determine with greater specificity the location of facilities, material requirements, and additional risks. Examples of engineer data are: height and distance measurements of facilities, inspecting conditions of existing facilities, soils analysis, soils thermal resistivity tests, and affected customers. The project engineer's design fidelity improves as he/she obtains more data, and the project's cost estimate is further refined and improved.

<u>Land Survey</u>

Land surveys also assist in determining the location of facilities. The survey may identify easements and property lines that are different from land records, which could result in changes to the scope of work and the cost estimate.

<u>Material Cost/Procurement</u>

Throughout a project's timeline, changes in the procurement price of materials will affect the cost estimate.

Permits

The duration of obtaining permits vary, and may cause delays to the project's schedule and an increase to the cost estimate. For example, based on past projects it may be determined that the proposed project should require just an over the counter review for a City street usage permit. However, policies or stricter enforcement of existing policies may require a detailed engineer review by the City.

Contractor Bids

In the cost estimation process, the contractor's cost is estimated based on historical data. Current conditions faced by the contractors (i.e., how busy they are) will affect their bids and may result in significant differences in the contractor costs originally estimated.

Government Policies

Changes in government policies may cause uncertainties in the project's cost estimate. For example, the City recently required that all underground ductlines be buried at least 3 feet below the surface (instead of 18 inches).

Revised Customer Request

The project engineer's cost estimate is based on the scope of work required to complete the customer's original request. If the customer's request changes throughout the project's schedule, then new cost estimates will be developed to reflect those changes.

Q. Should the Company wait until more detailed engineering and design can be completed, and a better cost estimate is available, before filing a PUC application?

A. No. The submission of the application is typically driven by the project's need to be in service and the application requirement to meet the Commission's General

Order No. 7, paragraph 2.3(g)(2), as modified by Decision and Order No. 21002, filed May 27, 2004, in Docket No. 03-0247 ("General Order No. 7") Working backwards from when a project needs to be in service, the Company tries to identify the longest-lead material items and the appropriate time to be installed to meet the service date. The Company then determines when those material items need to be ordered in time to arrive in Hawaii so it can be installed to meet the service date. This dictates when the application should be filed. Therefore, in many instances, the application is filed early (without much detailed engineering) in the project life to ensure that the longest-lead material item arrives in time.

In addition, the Commission's General Order No. 7 states that "proposed capital expenditures … in excess of $2.5 million, excluding customer contributions … shall be submitted to the Commission for review at least 60 days prior to the commencement of construction or commitment for expenditures, whichever is earlier." Under a strict reading of this rule, all expenditure of funds related to a specific project would be prohibited prior to 60 days. This would preclude the expenditure of funds for engineering and design necessary to prepare an adequate application. However, in Decision and Order No. 11005, filed March 14, 1991 in Docket No. 6571 ("Waikpau 69 kV Relocation"), the Commission stated that "rule 2.3(g)(2) should not be read so strictly that it prohibits any expenditure of funds related to a specific project. The expenditure of some amounts of money may be required for preliminary assessment and preliminary design and for the preparation of an application for commission approval, and some of these expenditures may eventually be included in the total cost of the project. The commitment for expenditures referred to in rule 2.3(g)(2) is a commitment that signals a definite intent to proceed with a project." As a result, it is the Company's understanding that the expenditure of some amounts of money related to preliminary engineering and preliminary design for the preparation of an application for Commission approval is generally acceptable to the Commission. The engineering and design expenditures that signals a definite intent to proceed with a project are subject to approvals and the time restrictions of General Order No. 7, paragraph 2.3(g)(2). There is difficulty in distinguishing between preliminary and non-preliminary engineering and design work because of the trade-off between submitting an adequate or satisfactory application and a good one. Obviously, the more work that is put into preliminary engineering and design work, the more informative and accurate the Company's applications will be. As a result, it is a judgment call as to where preliminary engineering and design ends.

Q. What step are being taken in the Energy Delivery Process Area to improve the way cost estimates are prepared (i.e., better accuracy)?

A. As mentioned earlier in my testimony, the cost estimating process includes these basic steps: (1) identify scope of work, (2) identify deliverables, (3) identify risks, (4) create schedule and cost estimate. Some of the specific actions that the project engineers or project managers perform in the above process include the review of cost variances and "lessons learned" from past projects. In addition, respective estimating programs and data bases used by the engineers are continuously updated as project cost results are obtained.

To further improve the results from this process, the Energy Delivery Process Area advocates the Project Management Institute's[1] standard of project management entitled, "A Guide to the Project Management Body of Knowledge"

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[1] The Project Management Institute is the leading project management professional association with 420,000 members in seventy countries.

("PMBOK® Guide"). Some of the tools and methodologies that were derived from the PMBOK® Guide and tailored for Energy Delivery Process Area projects include: Project Initiation and Planning meeting guidelines, Scope Statement template, Work Breakdown Structure, Risk Planning tools, and contingency reserves. To introduce these tools and methodologies, a "Project Plan Development Class" is conducted periodically for Energy Delivery Process Area personnel. The class includes eight modules spread over approximately sixteen weeks on various project management topics related to project initiation and planning. A significant part of the curriculum includes the development of a robust project plan on a class project. To summarize, these classes emphasize the need to spend as much time and effort in the early planning stage of a project as the project timeline affords to develop a more realistic scope, schedule and cost estimate while achieving project objectives.

<u>ENERGY DELIVERY CAPITAL EXPENDITURE APPLICATIONS</u>

Q. Were there Energy Delivery related projects with 2008 and 2009 service dates for which capital expenditures applications were submitted pursuant to General Order No. 7?

A. Yes. In HECO-1704, Hawaiian Electric identified the projects approved by the Commission that will be placed in service and/or have straggling costs in 2008 or 2009. In the list of projects shown in HECO-1704, there were three Energy Delivery related projects that were placed in service in 2008, and none in 2009. Those projects are:

1) New Dispatch Center (New Energy Management System) project (Docket No. 03-0360), with the last component for that project completed in

February 2008;

2) Ko Olina Substation project (Docket No. 03-0056), completed in January 2008; and

3) Puuloa Road Improvements project (Docket No. 02-0413), completed in May 2008.

Q. What were the original and final costs for these projects?

A. For the New Dispatch Center (New Energy Management System) project, the total capital expenditures as of June 30, 2009 are approximately $27.2 million, which is approximately $4.3 million or 19% higher than the application cost estimate of approximately $22.9 million. (The costs are not final as there are outstanding charges for the project.) The Ko Olina Substation project was completed for approximately $3.8 million (net of customer contributions), approximately $1.0 million or 35% higher than the application cost estimate amount of approximately $2.8 million (net of customer contributions). The Puuloa Road Improvements project was completed for approximately $1.87 million (including approximately $100,000 in outstanding costs), which was approximately $690,000 or 59% higher than the application cost estimate amount of approximately $1.18 million. (The costs are not final as there are outstanding charges for the project.)

Q. Please provide explanations for the cost variances for these projects.

A. Explanations of the cost variances for each of the three projects are provided in the following paragraphs.

<u>New Dispatch Center (New Energy Management System)</u>

Q. Please provide a brief description of the New Dispatch Center (New Energy Management System) project.

A. The New Dispatch Center project, in Docket No. 03-0360, included the (1) installation of a modern, state-of-the-art Energy Management System ("EMS"); (2) construction of a new, more secure Dispatch Center Building and installation of an up-to-date Control Room with "dynamic" dispatch board displays, a Dispatcher Training Simulator ("DTS"), and other Dispatch Center facilities; (3) installation of a backup control center at a separate location; and (4) renovation work to allow for relocation of the Call Center, the Field Service and Meter Reading divisions, and storage facilities and parking that were displaced or relocated to accommodate the location of the new Dispatch Center Building at Hawaiian Electric's Ward Avenue facility.

Q. What made this project unique from other transmission and distribution and/or facilities projects?

A. The Dispatch Center and EMS is the nerve center of Hawaiian Electric's operations. The Dispatch Center consists of two key components: (1) the critical systems and personnel located in the Dispatch Office and (2) the physical Dispatch Center Building protecting the critical systems and personnel operating the systems. The EMS, which includes supervisory control and data acquisition ("SCADA"), Automatic Generation Control ("AGC") and Economic Dispatch, and Security Assessment, are extremely vital to the reliable operations of Hawaiian Electric's electrical system. Together, the Dispatch Center and EMS provide the dispatchers with real-time information on power system conditions, with the tools to remotely control the power system, to optimize generation dispatch, and to predict the impacts of, and analyze and manage power system upset and other emergency conditions. The estimated cost of the project was approximately $22.9 million.

Q. Did the Commission approve the expenditure of capital for the New Dispatch

Center (New Energy Management System) project?

A. Yes. In Decision and Order No. 21224, filed August 6, 2004, in Docket No. 03-0360, the Commission approved the Application for the New Dispatch Center (New Energy Management System) project.

Q. What is the status of the New Dispatch Center (New Energy Management System) project?

A. The last component of the New Dispatch Center (New Energy Management System) project was completed in February 2008. Individual project components were completed on different dates, starting in November 2005. An Interim Accounting Report ("IAR") filed on April 21, 2008 in Docket No. 03-0360 provides additional details on the New Dispatch Center project costs, and is hereby incorporated by reference. In the IAR, Hawaiian Electric estimated the total cost for the project to be approximately $27.5 million, with approximately $413,000 in remaining charges. Hawaiian Electric will file the Final Cost Report for the project after all the outstanding charges have been reconciled.

Q. Please provide the current capital expenditures and compare it to the PUC application amount.

A. The total capital expenditures as of June 30, 2009 are approximately $27.2 million, which is approximately $4.3 million or 19% higher than the application project estimate of approximately $22.9 million.

Q. Please provide a detailed cost variance explanation by project component.

A. A variance explanation is provided in the following paragraphs, with the component with the largest positive (i.e., overrun) cost variance explained first, and the component with the largest negative (i.e., under-run) cost variance explained last.

Dispatch Center Building (Component P000713)

The current actual cost for the Dispatch Center Building is approximately $13,775,000, which is approximately $2,159,000 or 19% higher than the original estimated cost of approximately $11,615,000 for this component. The actual construction costs were higher than the estimated construction costs primarily due to the increased cost of construction in Hawaii at the time the building was constructed in the late-2004 to early-2006 timeframe. The Dispatch Center Building was placed in-service in February 2006. Console Workstations purchased in the approximate amount of $261,000 from Evans Consoles Incorporated were also part of Component P0000713. These costs were similar to the estimated amount of $267,200.

Telecomm Extensions (Component P0000716)

The current actual cost for the Telecomm Extensions is approximately $3,155,000, which is approximately $1.7 million or 118% higher than the original estimated cost of $1,449,000 for this component. The cost increase is primarily due to: 1) the creation of a seamless transition of the EMS from the new system and back to the old system in the case that the new EMS failed soon after the final cutover; 2) elimination of a single point of failure on the communications paths to the EMS; 3) the purchase and installation of auxiliary equipment (besides the mobile radio consoles) to support the operations of the dispatch center and the seamless transition to the new dispatch center and back in the case that the new EMS failed soon after the final cutover; 4) additional telemetry requirements for AES and Kalaeloa; 5) the demolition of the communication circuits in the old dispatch center area including tedious research and wire tracing to verify that no circuits were missed; 6) the rerouting of systems affected by the demolition of the old dispatch center; and 7) the installation of communications for the new dispatcher training simulator room. The Telecomm Extensions were placed in-service in March 2006.

Call Center – 1st Floor (Component P0000794)

The current actual cost for the Call Center is approximately $1,557,000, which is approximately $1.1 million or 245% higher than the original estimated cost of approximately $451,000 for this component. The construction costs for the Call Center were higher than the estimated construction costs primarily due to the increased cost of construction in Hawaii at the time of the construction of the Call Center, similar to the variance explanation for the Dispatch Center Building. The Call Center was placed in-service in December 2006.

Dispatch Boards (Component P0000715)

The current actual cost for the Dispatch Boards is approximately $1,488,000, which is approximately $685,000 or 85% higher than the original estimated cost of approximately $804,000 for this component. The higher cost is primarily the result of the changes in technology that occurred from the time of the original cost estimate to when Hawaiian Electric was ready to select and order the dispatch boards. Hawaiian Electric selected the system that was the current generation of video display technology at the time of the order. Additionally, Hawaiian Electric increased the height of the video display boards by 2 feet from the original design of 6 feet, to a height of 8 feet. The additional 2 feet in height provides more real estate for critical information to be displayed. Also, since the time of the original cost estimate, the technologies in video display boards had advanced to provide increased visibility through increased viewing angles with a moderate increase in cost. The Dispatch Boards were placed in-service in

November 2005.

Field Service/Meter Reading (Component P0000793)

The current actual cost for the Field Service/Meter Reading is approximately $563,000, which is approximately $11,000 or 2% lower than the original estimated cost of approximately $574,000 for this component. The cost decrease is primarily due to the change in location of the renovations. Although the Field Service/Meter Reading areas were placed on the third floor of Ward II Building as planned, the existing office areas were renovated but not expanded to accommodate all of the personnel. The Field Service/Meter Reading was placed in-service in September 2007.

Materials Storage Relocation (Component P0000714)

The current actual cost for the Materials Storage Relocation is approximately $132,000, which is approximately $108,000 or 45% lower than the original estimated cost of $241,000 for this component. The construction costs for this component were lower primarily due to requiring fewer storage racks and less modification to the Ward Avenue facilities to relocate the displaced materials. The Materials Storage Relocation was placed in-service in April 2007.

Parking – C&M, SysOp, and Employee (Component P0000795)

The current actual cost for the parking areas for Construction and Maintenance, System Operations and Employee is approximately $251,000, which is approximately $280,000 or 53% lower than the original estimated cost of approximately $530,000 for this component. To minimize the total project expenditures, only minimal pavement repairs, asphalt seal coating, fence work, and pavement striping were done to accommodate parking needs for all areas at the Ward Avenue facility, as discussed in the Application. The Parking was placed in-service in February 2008.

EMS Replacement (Component P0000717)

The current actual cost for the EMS Replacement is approximately \$6,062,000, which is approximately \$387,000 or 6% lower than the original estimated cost of approximately \$6,449,000 for this component. The cost decrease is primarily due to the lower bid amount received in the bidding process for the EMS, back-up EMS, and Dispatcher Training Simulator ("DTS"). The bid prices received from the four EMS vendors covered a large range. (Hawaiian Electric's estimate fell within the range of the bids received.) Although Hawaiian Electric selected the lowest priced system, the system still meets the requirement set forth by the request for proposal. The EMS was placed in-service in March 2006. Also, Hawaiian Electric has elected to defer the installation of the back up EMS to an off-site location. The back up EMS is currently installed and located within the new Dispatch Center.

Dispatcher Training Simulator (Component P0000718)

The current actual cost for the Dispatch Training Simulator is approximately \$222,000 which is approximately \$574,000 or 72% lower than the original estimated cost of approximately \$797,000 for this component. The cost decrease is primarily due to the lower bid amount received in the bidding process that was used for the EMS and DTS. See the explanation for the EMS cost variance. The Dispatcher Training Simulator was placed in-service in December 2006.

Q. What actions or steps did Hawaiian Electric take to prudently manage the cost of the project?

A. Major components of the project were acquired through a competitive bidding process.

1) Hawaiian Electric solicited nine contractors to bid on the construction of the Dispatch Center building (Component P000713) and the Call Center (Component P0000794). Bids were only received from two of the nine contractors with the other seven declining to bid. The contract for the construction was awarded to Ralph S. Inouye Company Ltd.

2) Hawaiian Electric solicited four vendors to bid on the purchase and installation of the EMS and DTS. All four vendors submitted a bid. The contract was awarded to Siemens Energy Management & Information Services on February 16, 2005.

3) Hawaiian Electric solicited three vendors to bid on the purchase and installation of the Dispatch Boards. The request for proposal ("RFP") included a request for a base bid and alternate bids. (The RFP for the alternate bids also requested additional display wall controllers, a variety of service contract terms, lamp replacement programs, overhead projectors, and LCD flat screen monitors.) Bids were received from all three vendors. The contract for the purchase and installation of the Dispatch Boards was awarded on August 25, 2005 to Siemens Energy Management and Automation for a Barco video display board system that included one 48 feet wide by 8 feet high and one 16 feet wide by 8 feed high display boards, two controllers, and audio and video equipment. No service contract, lamp replacement program, overhead projectors, or flat screen monitors were purchased under this contract. A service contract and lamp replacement program was negotiated with Siemens under a separate agreement.

4) Hawaiian Electric solicited bids from four manufacturers for the fabrication

and installation of dispatcher consoles and millwork for the Dispatch Center (Component P000713) and DTS (Component P000718). Three of the four manufacturer's bid and one declined to bid. The contract was awarded to Evans Consoles Incorporated on October 21, 2005.

5) Hawaiian Electric solicited bids from three suppliers for major telecommunication components (Component P0000716) including a) copper terminations and cabling systems, b) equipment rack hardware, c) voice frequency patch equipment, d) fiber optic termination and cabling systems, e) category 3 cables, and f) fiber optic cables. Hawaiian Electric purchased equipment from all three suppliers based on the lowest cost for each individual piece of equipment.

6) Hawaiian Electric solicited five contractors to bid on the renovation of the Field Service and Meter Reading areas (Component P000793). Of the five contractors, three contractors submitted bid proposals. Hawaiian Electric awarded the renovations on April 17, 2007 to Prime Builders of Oahu.

7) Regarding the Parking Relocation for Construction and Maintenance, System Operation, and Employee vehicles (Component P0000795), Hawaiian Electric completed the work in two major phases. The first area is located on the mauka-ewa side of Hawaiian Electric's Ward Avenue facility. Hawaiian Electric requested and received proposals from two contractors. Walker –Moody Construction Company was awarded the work. The second area is located on the makai-Waikiki side of Hawaiian Electric's Ward Avenue facility. Hawaiian Electric requested and received proposals from three contractors. Hawaii Seal Coat was selected to complete the work mainly due to the completeness of their proposal and

schedule availability.

Please refer to Hawaiian Electric's New Dispatch Center IAR in Docket No. 03-0360 for additional information.

<u>Ko Olina Substation</u>

Q. Please describe the Ko Olina Substation project.

A. The Ko Olina Substation project in Docket No. 05-0056 involved: (1) the construction of a new system distribution substation in the Ko Olina development, (2) the extension of two existing 46kV subtransmission lines, partially overhead and partially underground, to the new substation site, and (3) the installation of one 15kV underground cable in an existing underground infrastructure from the new substation to the Ko Olina development. The estimated cost of the project was approximately $3.6 million (gross) or $2.8 million, net of contributions-in-aid-of-construction ("CIAC") of approximately $800,000.

Q. Did the Commission approve the expenditure of capital for the Ko Olina Substation project?

A. Yes. In Decision and Order No. 22001, filed August 31, 2005, as revised by Order No. 23125, filed December 11, 2006, in Docket No. 05-0056, the Commission approved the Application for the Ko Olina project.

Q. What is the status of the Ko Olina Substation project?

A. The Ko Olina Substation project was completed in January 2008 at a cost of approximately $5.0 million (gross) or $3.8 million, net of CIAC of approximately $1.2 million. An IAR was filed on March 31, 2008, and a Final Cost Report was filed on December 5, 2008, both in Docket No. 05-0056. Ko Olina Substation's IAR and Final Cost Report are hereby incorporated by reference.

Q. Please explain the higher actual costs for the Ko Olina Substation project.

A. The Ko Olina Substation project was completed for approximately \$3.8 million (net of CIAC), approximately \$1.0 million or 35% higher than the approved amount of approximately \$2.8 million (net of CIAC). The cost variance is primarily due to:

1) additional engineering design, material, and labor costs to complete the project in phases per request from Centex Destination Properties ("Centex", the adjacent developer/property owner) (the cost variance was offset to some extent by a contribution from Centex for the accelerated installation of one of two 46kV line extensions);
2) materials price increases due to the project delay and higher than estimated material costs;
3) higher than estimated outside construction costs; and
4) additional allowance for funds used during construction ("AFUDC") charges due to project delay.

Q. Please provide a detailed cost variance explanation for the reasons provide above.

A. A detailed explanation of the cost variances is provided as follows:

<u>Centex Destination Properties</u>

The Ko Olina Substation project originally had a service date of June 2006. However, due to delays in projected loads in the Ko Olina area, the service date was deferred by Hawaiian Electric to January 2008. Included in the scope of work for this project was the re-routing of a section of 46kV overhead line that bordered the Centex development. Based on the original June 2006 service date, this section of line was to be re-routed prior to Centex's construction start date for their adjacent development. However, due to the Ko Olina Substation's project deferral, the 46kV line re-routing would now occur after Centex's construction start date. As a result, Centex requested the installation of one of the 46kV line extensions by March 2007 instead of January 2008. The construction of the 46kV line extension would allow for the removal of the existing overhead 46kV line that bordered the Centex property.

This request by Centex required that the project be completed in phases (temporary and permanent). Since the Ko Olina Substation would not be completed by March 2007 for the termination of the 46kV line extension, additional engineering design, materials, and labor costs were incurred to install the 46kV line extension in a temporary configuration until the new Ko Olina Substation was completed in January 2008. The additional costs were offset to some extent by a contribution from Centex for the 46kV line extension.

<u>Higher Material Costs</u>

Due to the project deferral, the substation transformer, switchgear, and 46kV underground cable originally purchased for this project was used for another project (Item Y00045, Ocean Pointe Substation) that was starting construction. The new substation transformer, switchgear, and 46kV underground cable were re-purchased at a later date for this project at higher prices due to changing market conditions.

Additionally, subsequent to the completion of the original project design and during the project's deferral, the Commission adopted new rules for the installation, operation, and maintenance of overhead and underground electrical lines (i.e., Hawaii Administrative Rules Chapter 6-73, and the NESC 2002). As a result, the wood poles needed to be redesigned to meet the NESC 2002 requirements. This redesign resulted in requiring stronger and larger diameter poles, at a higher cost.

<u>Higher Outside Construction Costs</u>

The substation construction costs were higher than estimated due to the results of the soils test report that was completed during the detailed engineering phase of the project (after receiving Commission approval). The soils test results showed that the existing material at the substation site would not be suitable for compaction. As a result, additional existing material at the substation site had to be excavated and new material imported in for compaction.

Due to the project deferral, the 46kV duct line construction cost was higher than estimated due to the high demand in the construction industry market at the time of construction (2007 timeframe).

The pole hole excavation cost was higher than estimated due to the larger pole holes required for the larger poles and the unexpected encounter of hard rock, which required additional equipment and time for each pole hole excavation.

<u>Additional AFUDC</u>

Additional AFUDC charges were incurred due to the project deferral from June 2006 to January 2008. As stated earlier, the project deferral was due to the Developer's projected loads not materializing as originally scheduled. AFUDC was suspended for the substation and 12kV components of the project during the project's deferral, however, AFUDC for the 46kV component could not be suspended due to the early installation of the one 46kV line extension at the request of Centex.

Q. What steps did Hawaiian Electric take to prudently manage the costs for the Ko Olina Substation project?

A. For the Ko Olina Substation project, the distribution transformer was purchased through the Company's alliance with ABB, the switchgear was purchased through an alliance with Peterson Power, and the 46kV underground cable was purchased through an alliance with Prysmian. (In general, an alliance agreement provides Hawaiian Electric with favorable equipment/material pricing and faster delivery of the material or equipment through reduced engineering costs and/or factory cost savings.) The outside contractors for the 46kV duct line construction and the pole hole excavations were selected through a competitive bidding process. The 46kV duct line construction contract was bid out to two contractors, with Endo Electric as the successful bidder. The pole hole excavation contract was bid out to three contractors, with Ikaika as the successful bidder.

As mentioned above, AFUDC was suspended for certain project components when the project was deferred. In addition, as a project component was completed, AFUDC was stopped for that component.

Puuloa Road Improvements

Q. Please describe the Puuloa Road Improvements project.

A. The Puuloa Road Improvements project in Docket No. 02-0413 involved 46kV, 12kV, and secondary overhead and underground work primarily on Puuloa Road in the Mapunapuna area. The project was required as a result of the State Department of Transportation's ("DOT") widening of the existing two-lane Puuloa Road. Hawaiian Electric was required to relocate its existing overhead and underground facilities on Puuloa Road due to conflicts with the proposed road improvements. The estimated cost of the project was approximately $1.18 million (gross), and included an estimated contribution of approximately $486,000 by the State DOT.

Q. Did the Commission approve the expenditure of capital for the Puuloa Road Improvements project?

A. Yes. In Decision and Order No. 20089, filed March 21, 2003, in Docket No. 02-0413, the Commission approved the Application for the Puuloa Road Improvements project.

Q. What is the status of the Puuloa Road Improvements project?

A. The project was completed in May 2008, at an estimated final cost of approximately $1.87 million, which included approximately $100,000 in outstanding costs. An IAR was filed on June 26, 2008 in Docket No. 02-0413 that provides additional details, and is hereby incorporated by reference. A Final Cost Report, with all costs finalized, will be filed after all outstanding charges have been reconciled.

Q. Please explain the higher than estimated cost for the Puuloa Road Improvements project.

A. The Puuloa Road Improvements project was completed for approximately $1.87 million, approximately $690,000 or 59% higher than the approved amount of approximately $1.18 million.

A. The cost variance for the Puuloa Road Improvements project is primarily due to:

a) the higher than estimated cost for the installation of the steel poles and associated foundation work, which included a soils analysis study,
b) additional engineering and surveying costs to determine the exact locations for the steel poles,
c) additional contractor labor required to dig the larger and deeper pole holes than originally estimated,
d) the use of outside construction management to manage the project,
e) additional engineering costs which resulted from the numerous construction delays and field changes due to the relocation of other utilities (because of

unforeseen sub-surface road conditions and tight workspace), and

f) additional AFUDC charges due to project delays.

Q. Please provide a detailed cost variance explanation for the reasons provide above.

A. <u>Steel Poles and Foundation Work Revisions</u>

Hawaiian Electric had a soils study performed by Fewell Geotechnical ("FGE"), an independent soils consultant, to determine the soil conditions on Puuloa Road for the purposes of installing the steel poles. A soils study was performed during the detailed engineering design phase subsequent to receiving Commission approval because Puuloa Road was known to have poor soil conditions (i.e., loose soil below certain depth) on the mauka side and a high water table on the makai side. (This information was based on earlier studies done by the State DOT and others.) The FGE study recommended that Hawaiian Electric design bigger and deeper pole foundations with concrete to accommodate the loadings of the steel poles. Note that the timing of the Company's filing of the application was driven by the State DOT's original schedule and the need to approve a Utility Agreement between HECO and the State.

<u>Higher Engineering and Surveying Cost</u>

Due to the other utilities' construction activities going on in the vicinity, additional engineering efforts were needed to identify and locate the final pole locations. Hawaiian Electric installed the steel poles ahead of the work performed by the State DOT's contractor in order to lessen the amount of conflicts in the roadway. As a result, the steel pole locations had to be surveyed by Hawaiian Electric surveyors since the poles needed to be placed in the exact locations to be aligned with the rest of the roadway improvements (i.e., sidewalk, landscaping, curbs) that were constructed later.

Additional Construction Labor Costs

As a result of the larger and deeper pole holes that were required due to the poor soil conditions, the contractor required additional time and materials to complete the excavation. For example, additional concrete backfill was required for the larger and deeper holes. In addition, the presence of hard coral required additional time and labor to dig the holes. Per the State DOT's request, the contractor worked overtime to minimize shutting down the existing lanes and the placing of barricades on Puuloa Road during peak hours. Also, due to the poor soil conditions at the handhole locations (underlying soft soils, shallow water table, underlying soft lagoonal deposits, etc), the soil needed to be over-excavated and a stabilizing mud mat consisting of a geotextile stabilizing fabric and crushed rock needed to be installed a minimum of two feet below the bottom of the handhole foundations and a minimum of 2 feet laterally beyond its perimeters.

Outside Construction Management

Due to the complexity of the project and the additional coordination efforts that were required (with all of the other utility work at the project site), an experienced outside construction management service was used. HECO contracted TLH Construction Management to manage the complex construction coordination efforts. TLH was responsible for overseeing the contractors, coordinating the delivery of the materials, verifying the excavation and backfill depths, managing HECO's compressed construction schedule, etc.

Additional Engineering Cost

Due to the field changes that resulted from the relocation of existing utilities, discovery of undocumented utilities, etc., additional engineering time was required to make the necessary drawing and design revisions to reflect these field changes.

Additional AFUDC

Additional AFUDC charges were incurred due to the project delays. The project delays were primarily due to the delays by the State DOT in completing the final design and awarding the contract and notice to proceed (to Goodfellow Bros.) to start construction.

Q. What steps did Hawaiian Electric take to prudently manage the costs for the Puuloa Road Improvement project?

A. Hawaiian Electric manages its costs when the Company purchases outside materials and seeks outside construction. For this project, the construction contract was bid out, where Hawaiian Electric awarded the contract to the lowest evaluated bidder. The steel poles were obtained through a purchase alliance with Valmont, the Company's pole supplier. AFUDC was also managed by suspending the AFUDC charges once key project components were completed and considered used and useful.

Q. Does this conclude your testimony?

A. Yes, it does.

HAWAIIAN ELECTRIC COMPANY, INC.

KEN T. MORIKAMI

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. 820 Ward Avenue Honolulu, HI 96814
Position:	Manager, Engineering Department
Years of Service:	29
Education:	University of Colorado BS, Electrical Engineering (1977)
Previous Positions:	2004-Present HECO Engineering Department Manager
	1996-2004 HECO Project Management Division Director
	1989-1996 HECO Facilities & Project Management Department Project Manager
	1986-1989 HECO Engineering Research Division Program Engineer
	1982-1986 HECO Corporate Planning Department Corporate Planning Analyst
	1981-1982 HECO Distribution Engineering Department Distribution Planner

	1979-1981 HECO Engineering Department Transmission and Distribution Engineer
	1977-1979 City & County of Honolulu, Building Department Electrical Engineer
Previous Testimony:	PUC Docket No. 03-0417 East Oahu Transmission Project
	PUC Docket No. 2006-0386 HECO 2007 Rate Case
Professional License:	Professional Engineer – Electrical Branch, 1983
Professional Activities:	Hawaii Society of Professional Engineers - Past State President American Public Works Association – Past State President Waikiki Improvement Association – Board of Director Member Project Management Institute – Member Engineers & Architects of Hawaii – Member

SUPPLEMENTAL TESTIMONY OF
THOMAS C. SIMMONS

VICE PRESIDENT
POWER SUPPLY
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Cost Recovery of Generating Unit CIP CT-1

INTRODUCTION

Q. Please state your name and business address.

A. My name is Thomas C. Simmons and my business address is 475 Kamehameha Highway.

Q. By whom are you employed and in what capacity?

A. I am the Vice President, Power Supply at Hawaiian Electric Company, Inc. ("Hawaiian Electric" or "Company"). My educational background and work experience are provided in HECO ST-17E00

Q. Have you testified previously in this docket?

A. No, I have not.

Q. What is the purpose of your testimony in this docket?

A. The primary purpose of my testimony in this docket is to provide an overview and support Hawaiian Electric's justification for the costs of its capital projects included in Hawaiian Electric's 2009 test year rate case. In particular, my testimony and other testimonies provided by Hawaiian Electric support the position that the Commission should approve inclusion of the full costs for the new Campbell Industrial Park Generating Station and Transmission Additions Project (the "CIP CT-1 Project") in determining electric rates, as soon as the equipment goes into service. The CIP CT-1 Project involves Hawaiian Electric's proposal to add generating capacity on Hawaiian Electric's system consisting of (1) the construction of a new generating facility (including the acquisition of a simple-cycle combustion turbine generator and related equipment and auxiliary facilities) ("CT-1"), (2) the construction of a second 138 kV transmission line (approximately two (2) miles long) between the AES Substation and the Campbell Estate Industrial Park ("CEIP") Substation ("T-Line Addition"), (3) the expansion of Hawaiian Electric's existing Barbers Point Tank Farm site, and (4) the construction of substation upgrades for the AES Substation, CEIP Substation and Kahe Substation, and auxiliary equipment and facilities related to the foregoing.

In addition, my testimony outlines the current status of the fuel plan for obtaining biofuel for CT-1.

Q. Who else is providing testimony in this subject area?

A: In addition to Mr. Robert Alm who provides the policy testimony, there are five witnesses providing additional testimony in this area.

1. Mr. Robert Isler (HECO ST-17A) provides an overview of Hawaiian Electric's major project cost estimating process, discusses the cost increases related to CIP CT-1 Project costs, discusses CIP CT-1 Project estimates and cost management, and discusses the estimated in-service dates for CIP CT-1 Project;
2. Mr. Anthony Lunardini (HECO ST-17B) provides testimony regarding the CIP CT-1 Project cost estimating process and market factors affecting power industry costs during the time of CIP CT-1 Project estimates and construction;
3. Mr. Ross Sakuda (HECO ST-4) discusses the past and current continued need for the CIP CT-1 Project;

4. Mr. Dan Giovanni (HECO ST-7) provides testimony on the operational value of CIP-CT-1;
5. Mr. Brenner Munger (HECO ST-17C) provides testimony supporting the cost increases related to other power supply capital projects; and
6. Mr. Ken Morikami (HECO ST-17D) discusses cost estimating for energy delivery projects and supporting testimony explaining the cost increases for energy delivery capital projects.

<u>CIP CT-1 PROJECT</u>

Q. Why is the CIP CT-1 Project required?

A. As discussed in more detail in Mr. Alm's testimony, our customers are counting on Hawaiian Electric to provide safe and adequate electric service in a reliable manner such that, their lights, air conditioning, business equipment, television, computer, oven, stove, washing machine, dryer and microwave will go on when they need or want it. In order to meet this "obligation to serve" Hawaiian Electric must have a sufficient amount of generating capacity. As discussed by Mr. Sakuda, and as presented in Docket No. 05-0145, Hawaiian Electric identified a need for additional generation years ago. This need for additional generation led to the filing of an application on June 17, 2005 for approval of the CIP CT-1 Project.

Q. Did the Commission approve the expenditures for this new generating unit?

A. Yes. In Decision and Order No. 23457 ("D&O 23457") in Docket No. 05-0145, the Commission approved Hawaiian Electric's request to expend $137,430,260 for

CIP CT-1 and related transmission additions. In D&O 23457 the Commission recognized:

> the dire need for additional generation due to the reserve capacity shortfall faced by HECO in recent years. . . . all Parties agree that additional generation is needed on HECO's system. The Commission also finds that the need is immediate, and that the Project must be installed by July 2009 or as early as possible, as requested by HECO.

[D&O 23457, pages 42-43]

Q. Did Hawaiian Electric make the financial commitment to meet its "obligation to serve"?

A. Yes. As discussed in greater detail by Mr. Isler, Hawaiian Electric expended substantial funds in order to bring the CIP CT-1 Project on-line as soon as possible. Further, as indicated in the testimony of Mr. Robbie Alm (HECO ST-1), Hawaiian Electric is entitled to the recovery of the full costs of the CIP CT-1 Project, subject to Commission review and approval of the prudency of any costs actually incurred, based on the information known at the time of the initial application and once the generating unit is in-service.

Q. Notwithstanding Hawaiian Electric's commitment and expenditure of substantial funds for the CIP CT-1 Project to meet it "obligation to serve" based on the information known at the time approval was given to expend the funds, is there still an urgent need for new generation on the Hawaiian Electric system?

A. Yes. As explained by Mr. Ross Sakuda in HECO ST- 4, the CIP CT-1 Project is needed for the Hawaiian Electric system as it delivers on Hawaiian Electric's fundamental "obligation to serve" by maintaining an appropriate and responsible level of firm generating capacity on Oahu. Indeed, the primary need for CIP CT-1 Project is to counter Hawaiian Electric's reserve capacity shortfall situation. In a reserve capacity shortfall situation, there is a greater likelihood that customers may experience service interruptions due to the unexpected outage of one or more generating units, i.e., there is a higher probability that outages could occur.

Q. What other value does CIP CT-1 add?

A. As Mr. Giovanni testifies in HECO ST- 7, in addition to delivering on Hawaiian Electric's fundamental "obligation to serve" by maintaining an appropriate and responsible level of firm generating capacity on Oahu; it will 1) eliminate the need to commit up to two other cycling and/or peaking units to provide 30 to 50 megawatts ("MW") of generation and 60 to 80 MW of spinning reserve (achieved firing biodiesel, and not fossil fuel, thus reducing the "carbon footprint" of the generating system); and 2) will allow Hawaiian Electric to more effectively integrate increasing levels of renewable variable generation resources (such as wind and solar electric energy) into the Oahu grid.

Q. When is Hawaiian Electric expecting to put the new generating unit into commercial operation?

A. As of the time this testimony is being submitted, Hawaiian Electric still anticipates that CT-1 will be available for commercial operation by July 31, 2009. Additional work on balance of plant, tuning, and performance tests will continue through the third quarter of 2009. Nevertheless, once CT-1 is in service, CT-1 will be used to meet Hawaiian Electric's generation requirements.

Q. Why should the Commission approve the higher costs for CIP CT-1?

A. As discussed by Mr. Isler in HECO ST-17A, the actual costs incurred for the CIP CT-1 Project were reasonably incurred in order for Hawaiian Electric to meet its "obligation to serve." Therefore, Hawaiian Electric should be allowed recovery for reasonable investments made to perform its duties to provide reliable power to its customers. Mr. Alm, in HECO ST-1, addresses this issue from a regulatory perspective.

Q. Why are the project costs higher than the cost estimate prepared at the time the CIP CT-1 Project was approved by the Commission?

A. As discussed in the testimony provided by Mr. Isler in ST-17A and Mr. Lunardini in ST-17B, there are a number of valid reasons why the actual costs are higher than the costs estimated at the time the Commission approved the commitment of funds for the CIP CT-1 Project. Several factors combined to create a "perfect storm" of adverse circumstances that increased the costs for the CIP CT-1 Project. In fact, as explained in Mr. Lunardini's testimony, literally speaking, major storms and hurricanes in the southern U.S. in 2005 and 2006 were indeed a significant factor in driving up costs for materials, equipment and construction labor on a national scale that impacted costs in Hawaii.

Q. What were other factors that contributed to the cost increases for the CIP CT-1 Project above the original estimate?

A. Another major factor was the relatively early stage of project development at the time the original estimates were required for input to the regulatory process. Due to the complexity of issues in the CIP CT-1 project proceeding, the time period between filing and approval of the application was almost two years. If there is a long a time between the early stages of a project when the original estimate is developed and when engineering is completed, equipment is purchased and construction is started, actual costs can vary significantly from early estimates due to changed circumstances. For complex projects such as power plants, the original cost estimate requires numerous assumptions on scope, schedule, material costs and construction costs. In the case of the CIP CT-1 Project, there was a four year time period between the time the Company filed its application and the in-service date of the CT-1 unit. As addressed in the testimonies from Mr. Isler and Mr. Lunardini, the original estimate was based on the best information available at that time but that there were numerous changes from the assumptions used for the original estimate. Mr. Isler addresses these issues to explain the reasons why the CT-1 actual costs are higher than the original estimate. Mr. Isler's testimony is also supported by testimony from Mr. Lunardini which covers the specific methodology used and assumptions made to develop the preliminary cost estimates. Mr. Lunardini's testimony also addresses the significant factors on the global and national level that contributed to the cost increases on the CIP CT-1 project.

FUEL USE IN CT-1

Q. What fuel will be used in CT-1?

A. As outlined in previous testimonies submitted in Dockets Nos. 05-0145 and 2007-0346, CT-1 has an air permit from the State of Hawaii, Department of Health ("DOH") and Environmental Protection Agency ("EPA"), to be operated using naphtha or diesel. As explained in previous dockets, Hawaiian Electric will start up and run the performance guarantee tests for CT-1 using petroleum diesel.

Q. Didn't Hawaiian Electric agree to burn 100% biofuel in the new generating unit?

A. Yes. In the CT-1 docket, Docket No. 05-0145, the Consumer Advocate suggested, and Hawaiian Electric agreed to fuel the new generating unit using 100% biofuel. The Commission agreed that burning biofuel is preferable to fossil fuels and approved its use according to the joint stipulation ("Joint Stipulation") between Hawaiian Electric and the Consumer Advocate subject to the Commission's approval of the specific fuel purchase contract for the biofuel.

Q. How soon was it anticipated that Hawaiian Electric would burn 100% biofuel in the new generating unit?

A. In Hawaiian Electric's stipulated agreement with the Consumer Advocate, Hawaiian Electric agreed to an aggressive implementation of the process to run the CT unit on 100% biofuel and outlined the steps that it would take to establish a biofuel supply and secure the necessary permit modifications to allow the use of biofuel in the new generating unit.

Q. Has Hawaiian Electric complied with the agreement?

A. Yes, to the maximum reasonable extent possible.

Q. Was it ever contemplated that there would be some delays in being able to burn

100% biofuel in the new generating unit?

A. Yes. Because burning 100% biofuel in the Siemens SGT6-3000E CT has never been done before, there is no available emissions data using the type of biofuel planned to be used. This data is required to be submitted for approval of an air permit modification. The plan is to commission the unit using petroleum diesel. Once all performance tests were deemed complete, the plan outlined in previous testimonies in Dockets Nos. 05-0145 and 2007-0346 is to then burn biodiesel, obtain the emissions data, submit a request for the air permit modification along with the data, and to work with DOH and EPA to obtain approvals of the permit modifications needed use biodiesel as the normal fuel supply. This process is anticipated to take approximately up to six months.

Q. What fuel did Hawaiian Electric intend to use in the meantime?

A. The only fuel Hawaiian Electric is permitted to burn prior to modification of the air permit to accommodate biodiesel is petroleum diesel, and our expectation was to dispatch the CT-1 using petroleum diesel to fulfill CT-1's primary purpose which is to meet the capacity needs of the system in order to provide a reliable supply of power to our customers.

Q. Are there other possible events that could delay the use of biodiesel in the new generating unit?

A. Yes. Two that come to mind are 1) an interruption of biodiesel supply, and 2) to allow Siemens a cure period to remedy any performance deficiencies. These potential issues were contemplated in the stipulated agreement by a provision that

"If there is an interruption of the biofuel supply or an emergency or operational problem that would affect the use of the CT Unit, Hawaiian Electric will work with the Consumer Advocate and the Commission to attempt to address such contingencies."

Q. Has anything happened to cause this provision to be effected?

A. Yes. In Docket No. 2007-0346, which was the venue for seeking Commission approval of the specific biodiesel fuel purchase contract, Hawaiian Electric provided information on how the current worldwide economic downturn impacted the biofuel industry and in particular specific impacts to Hawaiian Electric's biodiesel fuel supplier that caused renegotiation of certain contract provisions inherently delaying approval of the biodiesel and terminalling contracts. As reflected in the record in that proceeding, Hawaii Electric has made its best effort to resolve these issues as soon as possible.

Q. How could the contractual agreements between Hawaiian Electric and Siemens relative to providing a cure period to remedy performance deficiencies impact the timing of the use of biodiesel in CIP CT-1?

A. In the Joint Stipulation between the Consumer Advocate and Hawaiian Electric regarding the use of biodiesel in CIP CT-1 in Docket No. 05-0145, the parties agreed as follows:

> Because the emissions data does not currently exist for biofuels and in order to ensure that ratepayer funds are spent effectively and wisely, Hawaiian Electric will implement the following process:

a. In general, the CT unit will go through acceptance testing using naphtha or low sulfur diesel in order to ensure that the CT Unit meets contract specifications and air permit requirements.

b. Following acceptance of the CT Unit, Hawaiian Electric will request DOH's approval to conduct testing at different loads using the chosen biofuel for which a supply contract has been executed, and to gather the emissions data needed to modify the air permit. After emissions data is collected using samples of the selected biofuel (i.e., biodiesel or ethanol), HECO will seek to modify the air permit to also allow 100% use of that biofuel. This entire process of collecting emissions data and modifying the permit could take up to 6 months depending on DOH requirements.

c. Following the air permit modification, the unit will then be run by burning biofuel (100%).

[Exhibit A to the Joint Stipulation]

If CIP CT-1 does not meet performance guarantees during acceptance testing then Siemens has up to nine months to address those performance issues. If Hawaiian Electric uses biodiesel to operate CIP CT-1 prior to Siemens demonstrating achievement of the performance guarantees, then the performance guarantees shall automatically be deemed to have been met (regardless of actual performance). Thus, Hawaiian Electric may need to evaluate whether it is in the best interest of its ratepayers to wait and require Siemens to meet their performance guarantees or to proceed with the use of biodiesel in the new generating unit..

Q. Has Hawaiian Electric aggressively pursued implementation of the process to run the unit on 100% biofuel?

A. Yes. Hawaiian Electric has done everything reasonable to ensure the use of 100%

biofuel in the new CT as expeditiously as possible. Hawaiian Electric sought to find a way for the potential fuel supplier to fulfill its obligations by renegotiating certain terms and conditions, and assuming responsibility for securing its own terminalling and transportation arrangements when it became apparent that forcing a termination of the existing contract would cause even longer delays in obtaining and getting Commission approvals for alternate arrangements through another procurement process.

Q. Is Hawaiian Electric still looking at ways to expedite the use of biofuel in the new generating unit?

A. Yes. We continue to negotiate with suppliers of smaller volumes of non-palm oil biodiesel which could possibly help reduce the time it takes to obtain the necessary air permit modifications to allow sustained use of biodiesel in the new generating unit. It may be possible to negotiate and get approval for purchase of a smaller volume of biodiesel to do the emissions tests prior to receipt of palm oil based biodiesel.

Q. Why hasn't Hawaiian Electric completed these negotiations?

A. Hawaiian Electric is still trying to negotiate pricing and delivery logistics for alternative supplies of biodiesel for emissions testing. There have been fuel specification issues, equipment availability issues, and fuel feedstock issues that have needed to be worked through. The disposition of these issues is constantly changing, and the viability of securing an alternative supply of biodiesel for emissions testing will depend on the costs and circumstances at the time an order for the fuel is actually executed.

Q. What is the status of the alternate source of biodiesel for CIP CT-1?

A. Hawaiian Electric is in the process of negotiating and finalizing a contract for a one-time purchase of biodiesel made from recycled cooking oil or “yellow grease.” This “yellow grease” biodiesel will conform to the fuel specifications established by Hawaiian Electric for the Siemens STG6-3000E generation unit based on the requirements from Siemens. Upon finalization of the contract, and if the Commission is amenable, Hawaiian Electric would submit an application to the Commission seeking approval of the contract and recovery of the costs if it looks like completing the process will result in reducing the time that it will take Hawaiian Electric to obtain an air permit modification from the DOH.

Q. Why does Hawaiian Electric believe that pursuing the yellow grease diesel alternative will help reduce the time to obtain an air permit modification?

A. Subject to PUC approvals, we understand that we may be able to obtain a limited supply of yellow grease diesel delivered to the CIP CT-1 site within several months of ordering the product. Provided that the specification issues, equipment availability issues, and fuel feedstock issues can be resolved in a timely manner, the purchase of the yellow grease diesel may expedite the overall process for the air quality permit modification and the conversion of the CIP CT-1 unit to 100% biodiesel operation.

Q. What is the quantity of yellow grease diesel that Hawaiian Electric plans to purchase?

A. Hawaiian Electric plans to purchase 275,000 gallons of yellow grease biodiesel to conduct emissions testing on the CIP CT-1 unit. To meet Hawaiian Electric's biodiesel fuel specifications for CIP CT-1, the yellow grease biodiesel will have to be reprocessed before shipment to Hawaiian Electric. It is expected that there will be a loss of up to 9% in the re-processing. Hawaiian Electric has estimated that 250,000 gallons of biodiesel will be required for the emissions testing. Therefore, 275,000 gallons of yellow grease diesel will need to be purchased and reprocessed to yield 250,000 gallons of biodiesel that complies with the Hawaiian Electric biodiesel fuel specifications.

Q. Are there any issues concerning the sustainability policy for biofuels that Hawaiian Electric has adopted?

A. No. Hawaiian Electric confirmed with the Natural Resources Defense Council ("NRDC") that yellow grease used to produce biodiesel is environmentally acceptable. As confirmed with the NRDC and stated in Mr. David Waller's letter to the NRDC dated April 29, 2009, the scope of the HECO-NRDC Environmental Policy deals explicitly with purpose-grown feedstocks and therefore an amendment to the Policy is not required. The processing of yellow grease into biodiesel generally represents a positive environmental approach for the manufacture of biodiesel.

Q. What is the status of the contract for the purchase of the yellow grease biodiesel?

A. The contract for the purchase of the yellow grease biodiesel is currently being negotiated although it is indeterminate at this time whether all of the issues can be resolved in order to make this a viable strategy. Our desire is to complete the negotiations by August 2009.

Q. What is the expected lead time for delivery of the yellow grease biodiesel to the CIP CT-1 site?

A. The delivery date for the yellow grease biodiesel is dependent upon supply and the timing of the Commission's approval for the yellow grease contract. Upon approval of the contract, the yellow grease product will be ordered and reprocessed for delivery to Hawaiian Electric. The supply and demand market conditions for yellow grease biodiesel are dynamic. Currently the estimated lead time including transit time from the time of contract execution to delivery at Campbell Industrial Park ranges from six to twelve weeks.

Q. What have been the recent changes in the yellow grease market that would impact the schedule for delivery of the re-processed biodiesel to the CIP CT-1 site?

A. From February through May, 2009, a yellow grease biodiesel supply was readily available to allow almost immediate shipment of the product with a total lead time ranging from four to six weeks. Since that time, market conditions have been changing. Currently, the lead time to acquire a yellow grease biodiesel supply for delivery to reprocess ranges from four to eight weeks. Re-processing the biodiesel and shipping to Hawaii will add two to four weeks to the total lead time. Therefore, the current estimated total lead time ranges from six to twelve weeks, subject to market supply and demand conditions at the time of contract execution. Notwithstanding the variability of the yellow grease market and the estimated times for purchase, re-processing and shipment to Hawaii, it is possible that subject to Commission approval, a one-time supply of yellow grease biodiesel can be delivered to the CIP CT-1 site two to three months sooner than biodiesel manufactured from palm oil. .

Q. What are the logistics for delivery of the yellow grease diesel to the CIP CT-1 site?

A. Delivery of the yellow grease biodiesel directly to Hawaiian Electric's generation site at Campbell Industrial Park will be included in the contract biodiesel price per gallon. Hawaiian Electric anticipates that the biodiesel will be shipped in standardized containers that hold approximately 6,250 gallons of biodiesel each. Based on 250,000 gallons or more of biodiesel to be delivered, approximately forty to forty-two containers will be needed. The containers will be off loaded at either Sand Island or Barbers Point Harbor and transported by truck to Hawaiian Electric's CT-1 fueling station at Campbell Industrial Park. Upon arrival at the fueling station, the biodiesel will be pumped from the containers directly into Hawaiian Electric's fuel storage tank for consumption during the DOH emissions testing of biodiesel.

Q. What will Hawaiian Electric do if the Commission does not approve the biofuel contracts which are currently being requested for approval?

A. If contract approvals are denied, Hawaiian Electric will seek to understand the reasons for such denial, and re-initiate a procurement process that addresses said reasons as expeditiously as possible. To ensure the reliability of electrical service to its customers, Hawaiian Electric intends, in the meantime, to operate the new CT under the provisions of its existing air permit.

OTHER CAPITAL PROJECTS

Q. Do you have any comments relating to other capital projects?

A. Yes. In addition to the funds expended for the CIP CT-1 Project, Hawaiian Electric reasonably expended funds for major capital projects related to power supply and energy delivery in order to meet Hawaiian Electric's obligation to serve. Mr. Munger addresses the reasonableness of the major capital expenditures (other than the CIP CT-1 Project which is discussed by Mr. Isler) made by the Power Supply Engineering Department of Hawaiian Electric. Mr. Morikami discusses the reasonableness of the expenditures made by the Energy Delivery Process area of Hawaiian Electric. Mr. Morikami also discusses the process for developing cost estimates for Energy Delivery Process area. Mr. Isler discusses the process of developing cost estimates for the Power Supply Engineering Department.

Q. Does this conclude your testimony?

A. Yes, it does.

HAWAIIAN ELECTRIC COMPANY, INC.

THOMAS C. SIMMONS

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. 475 Kamehameha Highway P. O. Box 2750 Honolulu, Hawaii 96840
Position:	Vice President, Power Supply
Years of Service:	38 years
Education:	Master of Science in Electrical Engineering, University of Hawaii, 1976 M.B.A., University of Hawaii, 1974 Bachelor of Science in Electrical Engineering, University of Hawaii, 1971 (With Honors)
Experience:	2002 - Present Vice President, Power Supply Hawaiian Electric Company, Inc. 1995 - 2002 Manager, Power Supply Services Department 1992 - 1995 Manager, Generation Planning Department 1980 - 1992 Senior Planning Engineer, System Planning Department 1987 - 1988 Management Internship Training Program Production, System Operations, and Financial Analysis Depts. 1975 - 1980 Electrical Engineer, System Planning Department

Experience (cont'd)	1971 - 1975 Designer, System Planning Department
Other Curriculum:	Public Utilities Executives Course University of Idaho, 1997.
	Utility Finance and Accounting, Financial Accounting Institute, 1990.
	EEI Senior Middle Management Development Program, 1993.
	Decision Analysis Techniques, Decision Focus, Inc., 1987.
	Utility Resource Planning: Supply-Side & Demand-Side Analyses, Cornell University, 1986.
	Stone and Webster Utility Management Development Course, 1985.
	General Electric Management Practices Course, 1984.
	Public Utilities Reports Guide Course, HECO, 1976.
Other Qualifications:	Registered Professional Engineer, Hawaii Electrical Branch, Since 1975 Industrial Branch, Since 1976
Previous Testimonies Before Public Utilities Commission:	
	Docket No. 05-0145, Campbell Industrial Park Generating Station and Transmission Additions Project.
	Docket No. 03-0372, Competitive Bidding for New Generation
	Docket No. 00-0135, Apollo Complaint Proceeding
	Docket No. 99-0207, HELCO 2000 Test Year Rate Case, 2000
	Docket No. 94-0079, PPA Negotiations with Enserch Development Corporation, 1995.
	Docket No. 7956, PPA Negotiations with Kawaihae Cogeneration Partners, 1994.

Docket No. 7259, HELCO Integrated Resource Planning, 1994.

Docket No. 7258, MECO Integrated Resource Planning, 1994.

Docket No. 7257, HECO Integrated Resource Planning, 1993.

Docket No. 7310, HECO, HELCO, MECO, Avoided Cost Investigation, 1993.

Docket No. 7261, GASCO Integrated Resource Planning, 1993.

Docket No. 7744, MECO Maalaea Dual-Train Combined Cycle Unit Number Two, 1993.

Docket No. 7766, HECO 1995 Test Year Rate Case, 1993.

Docket No. 7700, HELCO 1994 Test Year Rate Case, 1993.

Docket No. 7623, HELCO Keahole Combustion Turbine CT-5 and Keahole Steam Turbine ST-7, 1993.

Docket No. 7048, HELCO Keahole 20 MW Combustion Turbine, CT-4, 1993.

Docket No. 6983, HPOWER Firm Capacity Amendment regarding the treatment of HPOWER firm capacity and its payment, 1992.

Docket No. 6617, Instituting a proceeding to require energy utilities in Hawaii to implement Integrated Resource Planning, 1991.

Docket No. 6603, MECO Application to commit funds for purchase and installation of a Combined Cycle Unit, 1990.

Docket No. 6378, HECO Application for approval of Kalaeloa Power Purchase Contract, Interim CT Lease and related costs to include costs in its Fuel clause and for declaratory ruling as to H.R.S. 269-1, 1989.

Docket No. 5081, HECO 1995 Test Year Rate Case, 1984.

Docket No. 3933, HECO Application to commit funds for construction of Makalapa-Iwilei 138 KV Line, 1980.

SUPPLEMENTAL TESTIMONY OF
TAYNE S. Y. SEKIMURA

SENIOR VICE PRESIDENT, FINANCE AND ADMINISTRATION
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Purchased Power Adjustment Clause

INTRODUCTION

Q. Please state your name and business address.

A. My name is Tayne S. Y. Sekimura and my business address is 900 Richards Street, Honolulu, Hawaii, 96813.

Q. By whom are you employed and in what capacity?

A. I am the Senior Vice President, Finance and Administration of Hawaiian Electric Company, Inc. ("Hawaiian Electric" or the "Company"). HECO-2000 provides my educational background and work experience. I previously submitted direct testimony in this docket as HECO T-20 and rebuttal testimony as HECO RT-20.

Q. What will your supplemental testimony address?

A. My testimony will address Section III.(b) of the Commission's *Interim Decision and Order* ("ID&O"), issued July 2, 2009 in this proceeding, regarding the Purchased Power Adjustment Clause ("PPAC").

Q. What did the ID&O say relative to the PPAC proposed by Hawaiian Electric?

A. The ID&O stated that:

> In its update to HECO T-22, HECO has proposed the PPAC pursuant to Section 30 of the Energy Agreement. The commission finds, however, that more information is needed to determine the reasonableness of this surcharge.

See, ID&O at 14.

Q. What additional information is in the record in this proceeding to support the reasonableness of the PPAC?

A. In addition to Mr. Young's Rate Case Update, HECO T-22, additional information regarding policy considerations and the substantive merits of the PPAC is included in the following:

- my direct testimony, HECO T-20, pages 13 to 17, 22 to 23, 33 to 41, and 48 to 50;
- HECO-2016;
- Mr. Alm's Rate Case Update, HECO T-1, pages 7 to 8;
- my Rate Case Update, HECO T-20, pages 1 to 6, and Attachment 1;
- Mr. Alm's rebuttal testimony, HECO RT-1, pages 32 to 33;
- my rebuttal testimony, HECO RT-20, pages 18 to 21;
- HECO-R-2007;
- HECO-RWP-2007; and
- the Company's responses to CA-IR-380; DOD-IR-133; DOD-RIR-9; and DOD-RIR-21.

To facilitate review of the PPAC proposed by the Company, the following testimony summarizes the testimonies and updates referred to above in support of the reasonableness of the PPAC.

Q. What policy considerations are included in the record?

A. Policy considerations are included in Mr. Alm's Rate Case Update, HECO T-1, where he testifies that the PPAC is part of the Energy Agreement that was entered into on October 20, 2008. He further testifies that the PPAC is proposed in this rate case because the PPAC will transfer recovery of purchased power costs from base rates to a new surcharge. See, Rate Case Update, HECO T-1, at 7-8; HECO RT-1, at 32. Additionally, the new RPS law puts Hawaii at the forefront of renewable energy implementation. However, there is uncertainty as to the impact on reliability and service quality of integrating such high levels of intermittent renewable energy into the Company's grid, and what as to the financial commitments that it will take to achieve successful integration of such resources.

Attachment 1 of my HECO T-20 Rate Case Update provided a November 26, 2008 credit profile issued by Standard & Poor's ("S&P") that discussed the risks of the Energy Agreement. S&P's credit concerns focused on three areas: the feasibility of the plan and what the ramifications are for Hawaiian Electric if it cannot meet the ambitious program outlined in the agreement, the costs of the program and whether ratepayers would ultimately be willing to bear them, and the potential impact on reliability. S&P pointed out that electric system reliability would be a major credit consideration going forward as the issues presented by integrating substantial intermittent solar, wind and distributed generation resources are not trivial. The profile concluded that the next few years are likely to be pivotal for Company credit quality as the Energy Agreement details will likely shape the Company's financial position for years to come.

Q. What additional testimony has Mr. Alm submitted regarding the PPAC?

A. In Mr. Alm's rebuttal testimony, HECO RT-1, he testifies that purchased power costs are largely existing costs that are already in base rates, as opposed to incremental costs of new projects that have not yet been incorporated into rates. Purchased energy costs would continue to be recovered through the Energy Cost Adjustment Clause to the extent they are not recovered through base rates. Also, the Company did not remove any purchased power costs from the test year revenue requirements. See, HECO RT-1, at 32-33.

Q. What substantive justification for the PPAC is included in the record?

A. I testify in the Rate Case Update HECO T-20 that the PPAC is reasonable and should be approved, as it will enhance the Company's financial profile and help maintain Hawaiian Electric's current credit rating. See, Rate Case Update, HECO T-20, at 1; HECO RT-20, at 20. Additionally, in my direct testimony, I provide extensive testimony on the impact of power purchase obligations on the Company's risk profile, including a detailed discussion of imputed debt. See, HECO T-20, at 33-41.

Q. What benefits will the PPAC provide by enhancing the Company's financial profile and maintaining its credit rating?

A. A financially stable utility will be able to invest in new renewable resources and infrastructure to facilitate the addition of new renewable resources from independent power producers, to convert the existing system to renewable technologies. See, Rate Case Update, HECO T-20, at 1. In addition, renewable purchased power development will be promoted, because a company with a strong credit rating is more likely to attract renewable resource developers than a company with a weak credit rating. A creditworthy off-taker helps to attract prospective independent power producers. See, HECO RT-20, at 20. Also, enhancing the Company's financial profile and maintaining its credit rating will enable Hawaiian Electric to support new clean energy initiatives under the Energy Agreement. See, Rate Case Update, HECO T-20, at 1.

Q. Why is the PPAC needed?

A. The long-term, fixed obligation nature of purchased power contracts negatively impacts Hawaiian Electric's credit quality. Although none of the Company's existing purchased power agreements ("PPA") appear on the Company's balance sheet as long term obligations, credit rating agencies "impute debt" for these long-term obligations, as discussed in greater detail in my direct testimony, HECO T-20, pages 33 to 41, and 48 to 50; Rate Case Update, HECO T-20, pages 2 to 6, including Attachment 1; and rebuttal testimony, HECO RT-20, pages 18 to 21.

Q. Why would the PPAC mitigate the negative impact of purchased power obligations on the Company's credit quality?

A. If the proposed PPAC is approved and results in a 25% risk factor assignment by the Standard & Poor's rating agency ("S&P"), the Company's imputed debt would decrease by $212 million. This is discussed in detail at HECO T-1, at 48-49; Rate Case Update, HECO T-20, at 3; and HECO RT-20, at 20.

Q. What is the basis for the 50% and 25% risk factors assigned by S&P?

A. S&P explains in its May 2007 publication:

> ….some regulators use a utility's rate case to establish base rates that provide for the recover of the fixed costs created by PPAs. Although we see this type of mechanism as generally supportive of credit quality, the fact remains that the utility will need to litigate the right to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. For such a PPA, we employ a 50% risk factor. In cases where a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, we employ a risk factor of 25% because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recover costs.[1]

Q. What benefit would accrue from lowering imputed debt by $212 million?

A. The reduction in imputed debt would improve the Company's financial ratios as viewed by S&P or could create room to accept more imputed debt from renewable PPAs, or some combination of the two. An improvement in the debt/total capital ratio, which would move HECO toward being able to support its current credit rating, would still result in a rating implied by that ratio that is below HECO's current credit rating of BBB. See, Rate Case Update, HECO T-20, at 3.

Additionally, S&P has indicated numerous times over the past few years that

[1] S&P Ratings Direct "Standard & Poor's Methodology of Imputing Debt for U.S. Utilities' Power Purchase Agreements" dated May 7, 2007, filed as HECO-2013.

HECO's financial ratios are weak for its current credit rating of BBB. S&P's most recent Research Update, dated May 27, 2009, revised HECO's outlook to negative (from stable), noting that the Company's credit metrics are only marginally supportive of the current BBB credit rating. A copy of the S&P report is provided as HECO-S-2001.

Q. How would customers benefit from approval of the PPAC, if the PPAC results in a lower imputed debt?

A. In order to continue to provide customers with reliable electric service, the Company foresees increasing needs for capital investment to maintain the reliability of the existing system as well as to support renewable energy development. To raise the necessary capital to make these investments, the Company needs access to the capital markets to be able to tap financial resources when needed for such capital investments. Alternative recovery mechanisms, such as a PPAC that helps to align cost incurrence with cost recovery, are supportive of credit quality and may facilitate raising capital at a reasonable cost. Being an island environment, Hawaii has no inter-ties to other sources of electricity and must build its own resources to meet its needs. This increases the significance of making investments in capacity and reliability, and underscores the importance of maintaining access to capital markets. See, HECO T-20, at 16 and 22-23

In the long term, customers could potentially benefit from approval of the PPAC, if the PPAC results in a lower imputed debt, through decreased interest rates and/or increased debt proportions (and lower common equity proportions) in Hawaiian Electric's capital structure. Lower interest rates and more debt/less common equity will result in a lower weighted cost of capital, a lower rate of return on rate base, and, ultimately, lower rates. See, HECO RT-20, at 21. More debt and less common equity in the Company's capital structure lowers the cost of capital, because the cost of debt is lower than the cost of common equity. See, HECO T-20, at 50.

Q. What mechanisms were included in the Energy Agreement to attempt to mitigate these risks?

A. The Energy Agreement attempts to balance the risks of integrating large amounts of renewable energy into the grid with certain recovery mechanisms that would enable the utilities to timely recover operating costs and capital investment and maintain their financial integrity. A financially strong utility is essential to the Energy Agreement's success since the utility would need to provide the infrastructure to transmit the renewable energy from the provider to the consumer and the ability of the renewable energy providers to obtain financing for their projects largely depends on the financial viability of the utility. Third-party project developers are able to finance their projects based on their purchased power agreements with credit-worthy purchasers – the electric utilities. Thus, degradation of the utility's credit quality would also be detrimental to third-party developers of renewable energy projects.

Q. What cost recovery mechanisms were included in the Energy Agreement?

A. The Energy Agreement calls for the establishment of a revenue decoupling mechanism (which would include decoupling sales from revenues, using a revenue balancing account ("RBA") and a revenue adjustment mechanism ("RAM") to allow rates to be adjusted between rate cases in order to reflect increases in O&M costs and rate base, a purchased power adjustment clause and the Renewable Energy Infrastructure Program/Clean Energy Infrastructure ("REIP/CEI") Surcharge.

Q. What other support for the PPAC is included in the record?

A. My direct testimony supports the reasonableness of the PPAC on a conceptual basis. In addressing the Company's business risk in general, I discuss several business risks underlying regulation, including regulatory action. See, HECO T-20, at 13-23.

Q. What are the business risks discussed in your testimony that are conceptually relevant to the PPAC?

A. Regulatory decisions that suggest the utility will not have regulatory support will increase the Company's risk profile, and place Hawaiian Electric's current credit ratings in jeopardy. A downgrade of Hawaiian Electric's credit ratings would increase the Company's cost of capital, and thus, ultimately, the rates that customers pay. See, HECO T-20, at 14.

Q. What kinds of regulatory actions are needed to maintain Hawaiian Electric's financial integrity?

A. Hawaiian Electric must continue to obtain regulatory rulings that:

1) give the Company a realistic opportunity to earn a fair return;
2) provide full cost recovery of prudently incurred costs on which the Company's investors make no profit;
3) assure cost recovery of and on necessary capital investments; and
4) provide a fair return on prudent investments.

See, HECO T-20, at 14.

Hawaiian Electric needs regulatory rulings which provide the Company the opportunity to realistically and consistently earn the rate of return deemed fair in order to help maintain its current credit standing. Rulings which are delayed or inconsistent with prior decisions, or which create uncertainty in the Company's future financial results could be detrimental to the rating agencies' assessment of the Company's business risk, the Company's credit quality, and the financial health of the Company. See, HECO T-20, at 17.

Q. How would Hawaiian Electric satisfy these four requirements to maintain its financial integrity?

A. First, in order to have a realistic opportunity to earn the return determined to be fair in a rate case, the Company needs cost recovery to align with cost incurrence, because sales are not growing and therefore cannot offset the increases in costs. Closer matching of cost incurrence with cost recovery can result within the traditional rate case process or between rate cases. Beyond traditional rate cases, the use of surcharge mechanisms would provide funds toward the costs and capital investments necessary to achieve the renewable standards established by policymakers. See, HECO T-20, at 14-16.

Second, assurances of timely cost recovery of prudently incurred expenses will lower the Company's business risk. Increased assurance of future recovery of all purchased power costs would also reduce investor risk perceptions relating to purchased power. See, HECO T-20, at 16. Hawaiian Electric receives no compensation for PPA expenses, but has earnings potential at risk if power purchase costs are not fully recovered in rates. See, HECO T-20, at 24.

Third, mechanisms which support timely return on and return of capital investments are supportive of credit quality. In order to raise the capital necessary to make capital investments to maintain the reliability of the existing system as well as to support renewable development, the Company needs assurances of recovery of its investments and adequate returns on those investments. See, HECO T-20, at 16-17.

Finally, rates must be established on an adequate rate of return on rate base so that the Company has the opportunity to meet investor return expectations. Investors will not provide the capital Hawaiian Electric needs unless they are confident that their investment will meet return expectations. See, HECO T-20, at 17.

Q. What role does Mr. Young have in the Company's proposal for a PPAC?

A. In Rate Case Update HECO T-l, Mr. Young addresses implementation of the PPAC, calculation of the Purchased Power Adjustment for each Proposed Rate Schedule, and preparation of the tariff provision for the PPAC. See, Rate Case Update, HECO T-22, at 1-4, including Attachment 1.

Q. Do electric utilities on the Mainland have adjustment clauses that permit them to recover PPA firm capacity costs between rate cases?

A. Yes. Arizona Public Service, Empire District Electric Company (Oklahoma), Florida Power & Light Company, and Gulf Power (Florida) have automatic adjustment clauses to recover PPA capacity payments. AmerenUE (Missouri) has a fuel adjustment clause that permits the recovery of capacity charges for power purchase contracts of one year or less. In addition, Potomac Electric Power Company had a fuel clause in the District of Columbia that included firm capacity cost recovery prior to retail competition beginning in 1995.

Q. Please summarize your testimony regarding the Commission's finding in its ID&O that more information is needed to determine the reasonableness of the PPAC proposed by Hawaiian Electric.

A. Mr. Young addresses implementation of the proposed PPAC, calculation of the Purchased Power Adjustment for each Proposed Rate Schedule, and the tariff provision for the PPAC in Rate Case Update, HECO T-22. Additional testimony in the record that provides policy and substantive justification of the reasonableness of the proposed PPAC is provided in Mr. Alm's Rate Case Update, HECO T-1, and HECO RT-1; and in my HECO T-20, Rate Case Update HECO T-20, and HECO RT-20.

Based on the record in this proceeding, the PPAC is reasonable and should be approved.

Q. Does this conclude your testimony?

A. Yes.

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May 27, 2009

Research Update:

Hawaiian Electric Co. Inc. Outlook Revised To Negative, Short-Term Ratings Lowered To 'A-3'

Primary Credit Analyst:
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Table Of Contents

Research Update:

Hawaiian Electric Co. Inc. Outlook Revised To Negative, Short-Term Ratings Lowered To 'A-3'

Overview

- Our rating action for parent Hawaiian Electric Industries (HEI) and its electric utility subsidiary Hawaiian Electric Company (HECO) reflects deterioration in the island economy that is likely to weaken 2009 and 2010 consolidated credit metrics. These credit metrics have been only marginally supportive of the current 'BBB' corporate credit ratings (CCR) assigned to the parent and HECO.
- We are revising the outlook to negative from stable for both HEI and HECO and lowering the parent and utility short-term ratings to 'A-3' from 'A-2' The ratings of HEI's other major subsidiary, American Savings Bank (ASB), are rated on a standalone basis by our financial institutions group and are not affected by today's rating actions.
- Our negative outlook on HEI and its subsidiary HECO reflects our sentiment that despite the potential for favorable regulatory improvements that may be approved by the Hawaii Public Utilities Commission (HPUC), these changes, if authorized, do not mitigate the potential for weakened consolidated credit metrics in 2009 and possibly 2010.

Rating Action

On May 27, 2009, Standard & Poor's Ratings Services revised the outlook of Hawaiian Electric Industries (HEI) and the ratings of a major subsidiary, Hawaiian Electric Co. (HECO) to negative from stable, and lowered the short-term ratings to 'A-3' from 'A-2'. All ratings for HEI and HECO, HEI's largest subsidiary are affirmed. HEI's other major subsidiary, American Savings Bank, or ASB, (BBB/Stable/A-2) is rated on a standalone basis by Standard & Poor's financial institutions group. ASB's outlook is stable.

Rationale

HEI is the holding company for HECO and its two subsidiary utilities, Hawaiian Electric Light Co. (HELCO) and Maui Electric Co. (MECO). HECO serves Oahu; HELCO serves The Big Island of Hawaii; and MECO serves Molokai, Lanai, and Maui. Collectively these utilities provides retail electric service to about 95% of the Hawaiian population. HECO and its electric subsidiaries are regulated by the Hawaii Public Utilities Commission (HPUC).

In 1988 HEI acquired ASB, a thrift savings and loan that management has been slowly transforming into a full-service commercial bank. ASB serves all islands and is one of the state's largest community financial institutions based on total assets as of Dec. 31, 2008. Excluding bank borrowings, which in the last two years have ranged from $0.68 billion to $1.81 billion, consolidated debt outstanding as of March 31, 2009, was $1.22 billion, and is principally composed of HECO and unsecured subsidiary utility debt of $905 million. Parent HEI has $307 million of unsecured medium-term notes outstanding as of the same date. Bank borrowings are managed by ASB at the operating level.

We view HEI's credit ratings to be derived principally from HECO's regulated operations, which in 2008 provided about 63% of consolidated net income and a larger share of cash flows. The risks and performance of ASB are considered as part of HEI's consolidated credit quality by looking at ASB as a source of cash distributions that HEI utilizes to pay its dividends and to support the more capital-intensive operations of HECO. While our published credit metrics are based on consolidated financial statements that include ASB, we also examine the performance of HEI and HECO deconsolidated from ASB.

The rating actions reflect our view that the next two years are likely to be challenging for subsidiary HECO, which in turn the parent relies on for cash flows to service its own obligations, chiefly debt repayment and common stock distributions. The islands are exhibiting decidedly recessionary trends, and the state's dependence on tourism to support the local economy suggests that the Hawaiian recession could ultimately be more severe than the rest of the U.S. Visitor statistics show significant decline. According to the Hawaii's Economic Analysis Division of the State Department of Business, Economic Development & Tourism (DBEDT) visitor arrivals declined by almost 11% in 2008 relative to 2007 and are forecast to drop another 6% in 2009. Similar declines in visitor expenditures are also occurring. Average hotel occupancy rates for the first quarter of 2009 were down 9.7% to 69.0%, relative to the first quarter of 2008.

Other economic indicators are also weakening. In March 2009, unemployment was 6.5%, up from 2.9% in March 2008. DBEDT forecasts that unemployment will increase another 2.1% in 2009. According to more recent unemployment statistics compiled by the U.S. Bureau of Labor and Statistics, Hawaii's April state unemployment was 6.9%. While this is lower than the current U.S. average of 8.9%, according to DBEDT data that has not been seasonally adjusted, civilian unemployment (e.g., excluding the state's large military population) is exceeding levels seen during prior recessions in 1982 and the mid-1990s. Prospects for a recovery are not expected until mid-2010. The DBEDT does not expect that key economic indicators including employment, state gross domestic product and visitor statistics to return to healthy levels until 2011.

These trends are depressing utility electric sales. Retail electric sales fell 7.4% in the first quarter of 2009, relative to the same period in 2008. While about two-thirds of this decline can be attributed to cooler weather, we believe that a 4% or greater decline in annual sales (weather adjusted) is possible, which will strain earnings and cash flows and could increase incremental borrowings. In the first quarter of 2009, HECO's net income fell to $14 million from $25 million for the same period in 2009.

Weaker sales are occurring at the same time that expenses and capital requirements are growing. HECO expects its operations and maintenance (O&M) expense to increase 13% this year, and cash flows are needed to offset borrowing requirements to fund capital investment, which includes the construction of a HECO 110 MW biodiesel power plant expected online in late summer 2009. To offset its costs HECO reached a stipulated settlement in its 2009 rate case. If approved by the HPUC, which could happen as early as July 2, 2009, the settlement would award HECO nearly $80 million in interim rate increase, or an increase of 6.2%.

While rate relief will provide some incremental cash support to HECO, sales declines will hurt credit metrics in 2009. We expect funds from operations (FFO) to total debt to decline from year-end levels of nearly 14% to around 10%. We expect HEI's debt to total capitalization (which includes large adjustments we make for pension and purchased power obligations) to increase from a year-end 2008 level of 60% consolidated to around 62% and FFO interest coverage to decline from its 2008 level of 3.4x to 2.8x. (This forecast assumes a 4% decline in HECO electric sales, and that HECO receives interim rate relief in July.) Given HEI's business profile is 'strong' and its financial profile is 'aggressive' these expected credit metrics, if realized, are weak for the current ratings.

Our forecast assumes the company maintains its expected dividend payout, which it has not disclosed. We would note that HEI's strong parent dividend profile has been sustained by good utility earnings (which have seen some weakening in recent years due to regulatory lag) and the strong earnings of the bank. This and a significant bank restructuring completed in June 2008 have enabled the company to maintain an aggressive dividend payout ratio that averaged 101% over the last five years. While from a credit perspective this has been relatively benign during the years that the Hawaiian economy prospered, the company's dividend policy may not be sustainable if the economy declines significantly erode credit metrics.

While we would note that the company favorably issued $110 million in new equity at year-end 2008, its willingness to offset incremental debt that arises from cash flow reductions at the utility by issuing additional equity may be diminished especially in 2009. The company's stock price has softened recently and in April 2009 it suspended its dividend reinvestment program (DRIP) program. We expect the DRIP suspension will at lower equity contributions this year.

ASB has historically been an important source of proceeds to meet HEI's common stock dividends, and our ratings for HEI reflect the expectation that it will continue to meet its forecast distributions to the parent. ASB has typically accounted for about 20% of HEI consolidated cash flows. ASB's earning asset base resembles that of a thrift, with single-family mortgages and mortgage-backed securities accounting for 70% of total assets. The bank's capital management policy previously focused on maintaining a target 7.5% Tier I leverage ratio. But with expectations for continued softening in the Hawaiian economy, ASB has instead maintained this ratio well above 8%. The bank typically distributes equity in excess of this level as dividends to HEI, which our forecast presumes will continue through 2009 and 2010.

While our outlook reflects the concerns that consolidated operations face in the next two years, the company may receive HPUC authorization to implement several regulatory mechanisms that could support credit quality as early as 2010.

In October 2008, HEI's utilities signed an agreement to support the objectives of the state's Clean Energy Initiative (CEI). The agreement contemplates fundamental changes that would essentially move HECO and its subsidiary utilities away from a fully integrated electric utility dependent on petroleum to fuel 77% of its generation to a transmission and distribution company that would purchase future power requirements from third-party renewable developers and from its customers through distributed generation projects such as solar photovoltaics. As part of the agreement, the utility would be permitted to introduce several key regulatory enhancements including:

- Decoupling revenues from electric sales, which would result in HEI's utilities being able to recover in the following year any lost revenues due to lower than forecast sales;
- Providing HECO and eventually HELCO and MECO with an annual revenue adjustment mechanism that would allow the company to annually reconcile actual to forecast O&M expenses and capital additions and would also look forward, resetting retail electric rates to reflect expected expenses for the coming year. This would greatly reduce regulatory lag, which has resulted in the company earning poor, single-digit returns on equity since 2003;
- Establishing a separate surcharge to allow the three utilities to pass through all reasonably incurred purchased power costs, including capacity payments through its fuel and purchased power adjustment mechanism that is already in place (This change would result in a lower debt imputation for the company's off-balance-sheet obligations under our power purchase criteria); and
- Creating surcharges to automatically collect the costs of funding sizable planned energy efficiency and renewable investment programs.

A HECO decoupling mechanism is pending before the HPUC as part of its settlement agreement. While the utility may be allowed to track in a balancing account sales declines for the last six months of 2009, it will not recover any cash under collections until 2010. As a result, it does not mitigate our near-term flow concerns for 2009. MECO and HELCO are expected to seek decoupling mechanisms in rate case applications that have not been filed. The design of the revenue adjustment mechanism has yet to be authorized but could occur in the fall of 2009 for use beginning in January 2010. Given that all these important mechanisms are pending and at best are not likely to be implemented to provide full year cash flow benefits to HEI's utilities until 2010 at the earliest, we view these proposed changes as more long-run enhancements than short-term features that will assist company in the next two years.

Short-term credit factors

The short-term corporate credit and commercial paper rating on HEI and HECO is 'A-3'. As of March 31, 2009, HEI had cash and cash equivalents amounting to $160.2 million on a consolidated basis, with cash and cash equivalents at HECO being $4.2 million. HEI and HECO do not face any remaining maturities in the next couple of years.

HEI and HECO both have revolving credit facilities totaling $100 million and $175 million, respectively, which expire March 31, 2011. The entire amounts were available for borrowings under their respective credit facilities as of March 31, 2009. While liquidity was tightening at year-end 2008 due to the company utilizing short-term borrowings to fund HECO capital investment, HEI issued $110 million in common equity in December 2008, using the proceeds primarily to pay down short-term borrowings. It also negotiated a new nine-month $75 million revolving credit facility that expires in September 2009. No balances were drawn as of March 31, 2009.

Despite HECO's reliance on purchases for a sizable portion of its power supply portfolio its collateral obligations required to support its commodity contracts are negligible. As a result, it is able to size its credit facilities to address general working capital requirements and to support capital investment until debt balances reach a sufficient size to support a long-term debt issuance.

Outlook

The negative outlook assigned to HEI reflects the potential for consolidated credit metrics to fall below our benchmarks over our outlook horizon due to Hawaii's weakening economy, which is expected to lower utility electric sales and put upward pressure on consolidated borrowing requirements. A ratings downgrade could occur if consolidated credit metrics fall significantly below our forecast expectations of FFO to total debt of around 10% and adjusted leverage at 62%. At the same time, if the company can manage through the current economic downturn, which is not forecast to abate until mid-2010, improvements to HECO regulatory mechanisms could boost the consolidated financial profile by stabilizing utility cash flows. These mechanisms have yet to be approved by the state's utility regulators.

Ratings List

Downgraded

	To	From
Hawaiian Electric Co. Inc.		
Commercial Paper (1 issue)	A-3	A-2
Hawaiian Electric Industries Inc.		
Commercial Paper (1 issue)	A-3	A-2

Ratings Affirmed

HECO Capital Trust III		
Preferred Stock (1 issue)	BB+	
Hawaiian Electric Industries Inc.		
Senior Unsecured (4 issues)	BBB	

Ratings Affirmed; CreditWatch/Outlook Action

	To	From
Hawaii Electric Light Company, Inc.		

	To	From
Maui Electric Company, Ltd.		
Corporate Credit Rating	BBB/Negative/--	BBB/Stable/--

Ratings Affirmed; CreditWatch/Outlook Action; Downgraded

	To	From
Hawaiian Electric Co. Inc.		
Hawaiian Electric Industries Inc.		
Corporate Credit Rating	BBB/Negative/A-3	BBB/Stable/A-2

Complete ratings information is available to RatingsDirect subscribers at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com; select your preferred country or region, then Ratings in the left navigation bar, followed by Find a Rating.

SUPPLEMENTAL TESTIMONY OF
STEVEN M. FETTER

On Behalf of

HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Financial Integrity

INTRODUCTION

Q. Please state your name and business address.

A. My name is Steven M. Fetter. My business address is 1489 W. Warm Springs Rd., Suite 110, Henderson, NV 89014. I am President of Regulation UnFettered, a utility advisory firm I started in April 2002.

Q. Are you the same Steven M. Fetter who filed direct and rebuttal testimony in this docket?

A. Yes I am.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this supplemental testimony to the Hawaii Public Utilities Commission (the "Commission") on behalf of Hawaiian Electric Company ("Hawaiian Electric" or the "Company").

Q. What is the purpose of your supplemental testimony?

A. In this supplemental testimony, I focus on the importance of the Commission providing Hawaiian Electric with timely recovery of funds prudently expended for its planning activities and capital investment (with a fair return) related to public policy goals, including greater use of renewable energy resources. I then discuss, based upon my experience as a state regulator, the importance of timely decision-making and the minimization of the negative financial consequences that can result from regulatory lag. Finally, I discuss the importance of Hawaiian Electric, the Commission and its Staff, and other stakeholders working in concert to maintain, and potentially improve, the Company's current 'BBB' category credit ratings.

Q. The Company incurs costs in the course of evaluating potential initiatives in advance of those potential initiatives being approved by the Commission. Should such costs be included in determining rates?

A. From my experience as a state utility regulator, utilities often study and evaluate for potential implementation policies that hold out promise for improving cost or reliability related to customer service, or other public policy gains such as greater use of renewable energy resources. It is wholly appropriate for funds prudently incurred for such purposes to be recovered in some manner. Similarly, the reasonableness of costs related to new plant additions should be made based upon the perception of the need for such plant at the time the utility made the decision to proceed. After-the-fact second guessing only serves to make utility management reluctant to take any steps other than those approved or ordered by the Commission, a certain recipe for stagnation and lack of preparedness.

Q. Would inclusion in rates of preparatory activities commit or imply a commitment by the Commission to approving the initiative?

A. No, I do not believe so. I would view such recovery to be related to the reasonableness of the utility exploring potentially beneficial options. I do not equate recovery of the cost of preparatory activities with ultimate or required approval of the initiative that is under review.

Q. Given that this jurisdiction uses a forward test year, is it sound regulatory policy to allow into rates, through a rate case, plant that is forecasted to be placed into service during the test year?

A. Yes, I believe so. I would encourage rate recovery alternatives that would render the utility financially whole while preserving the Commission's ability to provide appropriate recourse to compensate customers if such plant assets were never actually placed into service. I understand that in the past this Commission has allowed for step increases or phase-in of rates to track the progress of capital additions, rather than confining itself to average test year costs which could understate total capital expended due to timing inconsistencies. I also understand that the Commission has the ability to refund associated revenues if the utility were to fail to place the forecasted asset into service. Matching up such forecasted costs with timely and full recovery, or refund if appropriate, is consistent with the so-called "regulatory compact."

Q. Could you explain the concept of the regulatory compact?

A. Yes. Basically the regulatory compact provides a regulated utility with the ability to build and maintain a protected monopoly public utility infrastructure for the benefit of a customer base, and in return regulators set rates that those customers pay to provide the utility with the ability to recover all of its prudent costs along with a fair return on its invested capital.

Q. Are there alternative methods of providing recovery of prudent costs?

A. Yes. The most traditional manner would be for fair recovery to be achieved through the setting of base rates, ones that basically stay the same until another rate case is fully litigated or subject to an approved settlement. Alternatively, a rate surcharge (or adjustment mechanism) could be instituted to track costs as they occur and provide recovery as close in time to when the expenditures are made as is possible. There also can be a phase-in of rates, as I refer to above when I discuss step increases related to plant additions. Finally, cost recovery could be tracked and deferred until a later rate case, at which time those costs could be recovered along with appropriate carrying charges, or interest. The beneficial aspect of having alternative means of rate-setting is that it allows the Commission to effectuate policies that adhere as closely as possible to recovery of actual costs with a fair return on a timely basis.

Q. You emphasize timeliness. In your mind, is that a key ratemaking principle?

A. Yes, very much so. In fact, I view it as so important that during my tenure as Chairman of the Michigan Public Service Commission ("MPSC"), my colleagues and I put in place a case handling guideline that led to the elimination of the MPSC's case backlog for the first time in 23 years. Timely recovery of actual costs with a fair return should be the regulatory goal – it is consistent with the regulatory compact I describe above, and works to minimize regulatory lag which financially injures a regulated utility with no real remedial recourse.

Q. How do your views on timeliness fit with your understanding of the processes at this Commission?

A. Now I note that each utility commission in the U.S. has to confront stresses that come about as a result of the legislative framework under which it operates, so the Commission should not view this as a solitary attack on its practices. With use of a forward test year, any delay beyond the beginning of that test year results in regulatory lag, or the inability for a utility ultimately to recover all of its costs. That said, I do understand that circumstances can arise that preclude a decision being made by the beginning of the test year. A decision decided as close to the start of the forward test year minimizes such financial harm – and policies such as the step increases I describe above also help limit negative financial consequences.

Q. Clearly, the current global recession is having an impact on the financial standing of all regulated utilities. Could you provide your insights into how alternative regulatory responses to the current economic environment might impact the credit quality of a utility?

A. Yes, and in a way it gets back to the concept of the regulatory compact. In my rebuttal testimony, I discussed the extreme vulnerability that regulated utilities holding 'BBB' category credit ratings, such as Hawaiian Electric, face within the current global economic recession. I will not repeat that discussion here other than to emphasize the importance of this Commission providing recovery of Hawaiian Electric's prudent costs, including costs related to appropriate planning activities, along with a fair return on capital investment. In addition, I believe both customers and investors benefit if all stakeholders within this proceeding, including the Commission and its Staff, work in concert to maintain Hawaiian Electric's financial health as it sets out to initiate an historic capital investment program targeted at achieving significant public policy gains, including greater use of renewable energy resources. Finally, I note that, even with an interim D&O having been issued, the financial community will watch closely how this proceeding ultimately concludes with a final determination on rate relief for the Company.

Q. Do you have concluding thoughts on the issues discussed in this supplemental testimony?

A. Yes. Across the entire utility sector, the ability of a regulated utility to sustain, and potentially improve, its credit ratings is more important today than in the past to ensure access to capital at reasonable cost. The financial crisis highlights that for a utility like Hawaiian Electric, which has a need for substantial financing due to its projected capital program, it is paramount that its financial integrity be sustainable throughout its capital investment cycle.

I encourage a sensitivity on the part of the Commission to Hawaiian Electric's specific concerns and circumstances followed by actions that allow prudent expenditures made for the benefit of customers to be timely recovered. What that would mean here is ongoing financial support for the Company's prudent planning activities, followed by timely recovery of expenditures made in furtherance of its capital investment program. The ultimate goal should be to provide the Company with the ability to maintain, and potentially improve, its current credit ratings.

Q. Does this conclude your supplemental testimony?

A. Yes, at this time.

Witness HECO ST-21

has no supplemental exhibits.

HECO ST-22
DOCKET NO. 2008-0083

SUPPLEMENTAL TESTIMONY OF
PETER C. YOUNG

DIRECTOR, PRICING DIVISION
ENERGY SERVICES DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

SUBJECT: Cost-of-Service Study and Rate Design

INTRODUCTION

Q. Please state your name and business address.

A. My name is Peter C. Young and my business address is 220 South King Street, Suite 1201, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am director of the Pricing Division of the Energy Services Department at the Hawaiian Electric Company, Inc. ("HECO" or the "Company"). My experience and background are listed in HECO-300. I have previously submitted written direct testimony in this case as HECO T-3 and HECO T-22. I am also submitting supplemental testimony HECO ST-3.

Q. What is your area of responsibility in this supplemental testimony?

A. My testimony in HECO ST-22 will address the additional issues in Part III of the Commission's Interim Decision & Order dated July 2, 2009, regarding "Cost Allocation" and "Rate Design."

COST ALLOCATION

Q. What are the Commission's concerns regarding cost allocation?

A. The Commission identified two concerns regarding cost allocation in the Interim Decision and Order dated July 2, 2009: 1) The Commission is concerned about the justness and reasonableness of the Parties'[1] proposed allocation of cost increases, including whether the proposed increases for each customer class depart from the traditional functionalization, classification, and allocation methodology; and 2) The Commission is concerned that the Parties' proposal to implement the interim rate increase on a cents-per-kWh basis could inappropriately include fixed costs in the variable component of rates.

[1] The Parties are the Consumer Advocate, the Department of Defense, and the Company.

Allocation of the Proposed Revenue Increase

Q. What is the Company's response to the Commission's concern whether the proposed increases for each customer class depart from the traditional functionalization, classification, and allocation methodology?

A. The Company has employed functionalization, classification, and allocation methodologies to allocate the proposed costs and rate base to customer classes, as described in HECO T-22, pages 11-21, and as illustrated in exhibits HECO-2201 to HECO-2211 in direct testimony, and in HECO T-22, Attachment 1, pages 1-9 in the HECO rate case update. Functionalization, classification, and allocation methodologies are not used to determine rates for each customer class.

Q. How is the proposed allocation of revenue increase to customer classes made?

A. The proposed allocation of revenue increase to customer classes is made by balancing the revenue increase assigned to the classes and the rates of return proposed for the classes with the rates of return calculated for each of the classes before the revenue increase is allocated.

Q. How is the calculation of class rate of return before revenue increase made?

A. The allocated cost to serve each customer class, based on functionalization, classification, and allocation methodologies, is compared with the class' estimated revenues at current effective rates. An estimated rate of return on rate base is calculated for each class and for the Company. A rate of return index at current effective rates is calculated as the ratio of the class rate of return divided by the rate of return for the Company. The rate of return index at current effective rates is a measure of how the estimated class revenues at test year sales and current rates compare with the cost of service allocated to the class; a rate of return index value of 100% means that the class revenues recover the allocated class costs, and the class earns the same rate of return as the Company as a whole.

Q. How are the proposed class rates of return considered?

A. The proposed revenue increase establishes a proposed rate of return for the Company. The allocation of the revenue increase to rate classes is intended to move each class rate of return index at proposed rates closer to 100% than its respective class rate of return index at current effective rates. The proposed revenue increase is allocated such that each class' revenues are closer to the class cost of service at proposed rates, including a rate of return at the proposed Company rate of return.

Q. How is the class revenue increase considered?

A. In HECO T-22, page 22, HECO identifies a list of rate design concept considerations. The considerations of revenue stability and impact on customers apply to the allocation of proposed revenue increases to classes as well. In the class revenue increase proposal, HECO tries to achieve the rate of return goals described above, but limits the movement of the class rate of return index at proposed rates in order that the class revenue increase impacts do not differ by extremes or appear to burden a certain class or classes unreasonably.

Q. How are the above considerations reflected in the proposed allocation of class revenue increase?

A. In the Settlement Proposal, on Exhibit 1, page 85, the Parties have agreed to the percentage allocation of any final increase in electric revenues to the proposed six rate classes. In HECO ST-22, Attachment 1, page 1, the proposed revenue allocation to classes, based on the Settlement Agreement percentages, and the class rates of return and rate of return index at proposed rates are presented for the cost of service scenario based on the minimum system study[2]. For all rate classes, the rate of return index at proposed rates has moved higher or lower towards 100% from the rate of return index at current effective rates. This is accomplished by assigning a revenue percentage increase to Schedule R, Schedule J, and Schedule F that is higher than the Company total percentage increase, since these classes had rate of return index values at current effective rates of less than 100%. The revenue percentage increase assigned to Schedule G, Schedule DS, and Schedule P is lower than the Company total percentage increase, since these classes had rate of return index values at current effective rates of greater than 100%. In addition, the smallest revenue percentage increase assigned (to Schedule DS) is about 50% of the Company total percentage increase, while the largest revenue percentage increase assigned (to Schedule J) is about 125% of the Company total percentage increase, which demonstrates that the proposed class revenue increases, while spread differently to different classes, are not extreme.

Q. Can we conclude that the proposed revenue allocation to rate classes is reasonable?

A. Yes. The proposed revenue allocation to proposed rate classes that is presented in the Settlement Agreement is reasonable. The proposed revenue allocation balances the impact to customer classes while moving each class' revenues closer to its proposed cost of service, which is determined based on functionalization, classification, and allocation methodologies.

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[2] The same presentation based on the cost of service scenario where all distribution-network costs are classified as demand-related is presented in Attachment 1, page 2.

Implementation of the Interim Rate Increase

Q. Did the Company propose to implement the interim rate increase on a cents per kWh basis?

A. Yes. As described in HECO T-1, pages 20-21, and in HECO T-22, pages 56-57, the Company proposed to implement the interim rate increase on a cents per kWh basis to each rate class. In the Settlement Agreement, the Parties agreed to implement the interim rate increase on a cents per kWh basis.

Q. Has the Company modified its position?

A. Yes. In consideration of the Commission's concerns about the implementation of the interim rate increase that were expressed in the Interim Decision and Order dated July 2, 2009, at pages 15-16, the Company, in its Revised Schedules Resulting from Interim Decision and Order, filed July 8, 2009, in Exhibit 2A, page 1, proposed to implement the interim rate increase as percentage increases assigned to customer classes, as has been done in the implementation of interim rate increases in the most recent rate cases for the HECO Companies[3]. By implementing the interim increase as a percentage, the underlying rate design and recovery of costs through customer, energy, and demand charges based on the HECO 2005 test year rate design approved by the Commission remains unchanged. Changes to the rate design and to the recovery of costs through the rate schedule charges would be made only upon approval in Commission final decision and orders in the HECO 2007 test year and HECO 2009 test year rate cases.

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[3] The HECO Companies are the Hawaiian Electric Company, Inc., the Hawaii Electric Light Company, Inc., and the Maui Electric Company, Ltd.

RATE DESIGN

Q. What are the Commission's concerns regarding rate design?

A. The Commission identified three questions regarding rate design in the Interim Decision and Order dated July 2, 2009: 1) Are the time-of-use ("TOU") rates incorporated in rate design for the purpose of incenting off-peak use and dis-incenting on-peak use; 2) Is this the proper proceeding to consider TOU, or should it be more appropriately considered in the AMI docket; and 3) Can the State make progress toward energy efficiency through rate design without AMI?

Q. Are the TOU rates in the rate design for the purpose of incenting off-peak use and dis-incenting on-peak use?

A. The TOU rates that are proposed in the rate design are proposed revisions to existing TOU rates that were approved in the HECO 2005 test year rate case. The TOU rates are rate options; they provide customers with an additional choice. Customers have the opportunity to participate in TOU rates to reduce their electric bills by shifting kW and kWh consumption to usage periods where the rate charged is lower. Such a shift in usage could be from priority peak hours to mid-peak hours, from priority peak hours to off-peak hours, from mid-peak hours to off-peak hours, or some combination of the three[4].

Q. Is this the proper proceeding to consider TOU, or should it be more appropriately considered in the AMI docket?

A. The rate case proceeding is the proper venue to consider TOU and all other elements of rate design. It is particularly important to consider a TOU rate design option and its associated base rate design in the same proceeding in order to coordinate both rate proposals. The TOU rate proposals that are included in the

[4] The proposed residential TOU rate option has only two proposed usage periods, on-peak and off-peak.

AMI application in Docket No. 2008-0303 are the same TOU rate proposals that have been made in the open rate cases for the HECO Companies[5].

Q. Can the State make progress toward energy efficiency through rate design without AMI?

A. Yes. HECO has already proposed rate design changes that promote energy efficiency. For example, in the 2007 test year rate case and in the 2009 test year rate case, HECO has proposed inclining block rates for the residential service class. Also in the 2009 test year rate case, HECO has proposed a single demand charge rate for Schedule DS and Schedule P (which are the proposed rate schedules for existing Schedule PS, Schedule PP, and Schedule PT customers), replacing the declining block structure of the existing demand charges. In addition, greater alignment of class revenues with the class cost of service will promote energy efficiency.

Q. Does this conclude your testimony?

A. Yes, this concludes my testimony.

[5] The rate levels in the TOU rate option proposals in the AMI Docket have been adjusted to reflect current fuel adjustment clause prices rather than the fuel price level assumed in the respective rate cases.

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083, TEST-YEAR 2009

SUMMARY OF CLASS REVENUE REQUIREMENTS AND CLASS RATES OF RETURN
COST OF SERVICE BASED ON MINIMUM SYSTEM STUDY
AT CURRENT EFFECTIVE RATES AND AT PROPOSED RATES

	Current Effective Rates			Proposed Rates			Proposed Increase	
Rate Class	Sales Revenues	Rate of Return	ROR Index	Sales Revenues	Rate of Return	ROR Index	Amount	Percent
	($000s)	(%)	(%)	($000s)	(%)	(%)	($000s)	(%)
Schedule R	$402,450.6	2.78%	56.68%	$430,931.9	5.90%	69.82%	$28,481.3	7.08%
Schedule G	$83,980.6	10.16%	207.26%	$87,550.7	12.07%	142.84%	$3,570.1	4.25%
Schedule J	$350,923.2	4.00%	81.51%	$378,193.1	8.47%	100.24%	$27,269.9	7.77%
Schedule DS	$173,173.3	7.69%	156.81%	$178,799.4	10.96%	129.70%	$5,626.1	3.25%
Schedule P	$274,222.3	7.93%	161.87%	$288,454.9	11.99%	141.89%	$14,232.6	5.19%
Schedule F	$6,868.7	2.26%	46.15%	$7,378.7	5.90%	69.82%	$510.0	7.42%
Total Sales Revenues	$1,291,618.7			$1,371,308.7			$79,690.0	6.17%
Other Operating Revenues	$4,755.1			$4,876.9			$121.8	2.56%
Total Revenues	$1,296,373.8	4.90%	100.00%	$1,376,185.6	8.45%	100.00%	$79,811.8	6.16%

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HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083, TEST-YEAR 2009

SUMMARY OF COST COMPONENTS BY RATE CLASS AT PROPOSED RATES
COST OF SERVICE BASED ON MINIMUM SYSTEM STUDY

	COST COMPONENTS AT PROPOSED RATES							
Rate Class	DEMAND COSTS		ENERGY COSTS		CUSTOMER COSTS		TOTAL COSTS	
	($000s)	(%)	($000s)	(%)	($000s)	(%)	($000s)	(%)
Schedule R	$132,605.9	30.28%	$226,093.9	27.17%	$72,232.0	71.44%	$430,931.8	31.42%
Schedule G	$27,220.0	6.21%	$43,387.5	5.21%	$16,943.2	16.76%	$87,550.7	6.38%
Schedule J	$137,197.6	31.32%	$230,228.2	27.67%	$10,767.3	10.65%	$378,193.1	27.58%
Schedule DS	$46,091.3	10.52%	$132,483.1	15.92%	$224.7	0.22%	$178,799.1	13.04%
Schedule P	$91,841.5	20.97%	$195,866.3	23.55%	$747.4	0.74%	$288,455.2	21.04%
Schedule F	$3,081.0	0.70%	$4,099.4	0.49%	$198.5	0.20%	$7,378.9	0.54%
TOTAL	$438,037.3	100.00%	$832,158.4	100.00%	$101,113.1	100.01%	$1,371,308.8	100.00%
PERCENT OF TOTAL	31.94%		60.69%		7.37%		100.00%	

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083, TEST-YEAR 2009

SUMMARY OF UNIT COST COMPONENTS BY RATE CLASS AT PROPOSED RATES
COST OF SERVICE BASED ON MINIMUM SYSTEM STUDY

	Unit Cost Components At Proposed Rates			
Rate Class	Unit Demand Cost ($/kW/mo.)	Unit Energy Cost (¢/kWh)	Unit Customer Cost ($/Customer/mo.)	Total Unit Cost (¢/kWh)
Schedule R	$9.14	11.145	$22.97	21.243
Schedule G	$15.15	11.207	$53.00	22.615
Schedule J	$25.21	11.164	$130.51	18.338
Schedule DS	$19.50	11.007	$749.00	14.855
Schedule P	$25.14	11.094	$189.30	16.338
Schedule F	$27.36	10.932	$37.50	19.677
TOTAL	$15.71	11.118	$28.44	18.321

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083, TEST-YEAR 2009
SUMMARY OF ALLOCATION FACTORS
COST OF SERVICE BASED ON MINIMUM SYSTEM STUDY

ALLOCATION BASIS		Schedule R	Schedule G	Schedule J	Schedule DS	Schedule P	Schedule F	Total
Demand Allocation Factors:								
Average-Excess Demand	D1	31.57%	5.55%	30.46%	12.53%	19.12%	0.77%	100.00%
Class Peak Demand	D2	36.87%	6.37%	35.22%	0.00%	20.59%	0.94%	100.00%
Composite NCD	D3	51.21%	7.41%	28.19%	0.00%	13.08%	0.12%	100.00%
Energy Allocation Factors:								
Gross Input	E1	27.26%	5.20%	27.67%	15.90%	23.47%	0.49%	100.00%
Customer Allocation Factors:								
Primary Lines	C1	83.57%	11.90%	4.19%		0.20%	0.14%	100.00%
Secondary Lines	C2	86.94%	9.99%	2.90%		0.14%	0.03%	100.00%
Transformers	C3	30.02%	43.73%	23.89%		2.22%	0.14%	100.00%
Services	C4	83.67%	9.02%	6.57%	0.30%	0.21%	0.24%	100.00%
Meter	C5	62.35%	9.64%	24.68%	1.99%	0.94%	0.39%	100.00%
Cust Acct Fct	C6	85.47%	10.69%	3.50%	0.01%	0.16%	0.16%	100.00%
Bad Debt	C7	69.93%	7.85%	17.00%	1.72%	3.48%	0.02%	100.00%
Cust Serv Fct	C8	60.25%	4.56%	33.41%	0.12%	1.59%	0.07%	100.00%
Avg Cust	C10	88.42%	8.99%	2.32%	0.01%	0.11%	0.15%	100.00%

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083, TEST-YEAR 2009

SUMMARY OF CLASS LOAD FACTORS FOR REASSIGNED RATE CLASSES[1]

Rate Class	Class Peak kW	Date	Time	Normalized Class Peak	Class Peak Load Factor
Schedule R	1.97	11/1/2003	HR20		48%
Schedule G	3.43	5/27/2003	HR14	3.00	53%
Schedule J	67.30	11/5/2003	HR13	61.80	51%
Schedule DS	12,616.00	8/19/2003	HR14	7,596.00	77%
Schedule P	856.00	7/25/2003	HR15	862.00	74%
Schedule F	30.50	April 2003	HR19		34%

Notes:
[1] The 2003 Class Load Study dataset was used to reassign schedule H and Directly Served customers.

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083, TEST-YEAR 2009

SUMMARY OF CLASS REVENUE REQUIREMENTS AND CLASS RATES OF RETURN
COST OF SERVICE BASED ON ALL DISTRIBUTION NETWORK DEMAND RELATED
AT CURRENT EFFECTIVE RATES AND AT PROPOSED RATES

	Current Effective Rates			Proposed Rates			Proposed Increase	
Rate Class	Sales Revenues ($000s)	Rate of Return (%)	ROR Index (%)	Sales Revenues ($000s)	Rate of Return (%)	ROR Index (%)	Amount ($000s)	Percent (%)
Schedule R	$402,450.5	4.60%	93.76%	$430,931.8	7.90%	93.49%	$28,481.3	7.08%
Schedule G	$83,980.4	17.04%	347.58%	$87,550.5	19.61%	232.07%	$3,570.1	4.25%
Schedule J	$350,923.2	1.99%	40.60%	$378,193.1	6.09%	72.07%	$27,269.9	7.77%
Schedule DS	$173,173.4	7.69%	156.81%	$178,799.5	10.96%	129.70%	$5,626.1	3.25%
Schedule P	$274,222.3	5.14%	104.96%	$288,454.9	8.76%	103.67%	$14,232.6	5.19%
Schedule F	$6,868.8	0.70%	14.20%	$7,378.8	4.10%	48.52%	$510.0	7.42%
Total Sales Revenues	$1,291,618.6			$1,371,308.6			$79,690.0	6.17%
Other Operating Revenues	$4,755.1			$4,876.9			$121.8	2.56%
Total Revenues	$1,296,373.7	4.90%	100.00%	$1,376,185.5	8.45%	100.00%	$79,811.8	6.16%

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